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by: /s Lynn DInnocenti

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NPC and SPPC

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Energy Supply Plan Update for period 2023-2024.	Docket No. 22-09___

VOLUME 1 OF 2

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

TRANSMITTAL LETTER

September 1, 2022

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Energy Supply Plan Update for 2023 and 2024.

Dear Ms. Osborne:

Enclosed for filing please find Nevada Power Company d/b/a NV Energy's ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy's ("Sierra" and together with Nevada Power, the "Companies" or "NV Energy"), filing of their joint Application for Approval of their Energy Supply Plan Update for 2023 and 2024 (the "ESP Update"). The ESP Update contains three volumes and is organized as follows:

Volume 1 – Transmittal Letter, Table of Contents, Certificate of Service, Application, Draft Notice, Testimonies and Narrative
Volume 2 – Technical Appendices LF-1 through LF-6, POWER-1, GAS-1 through GAS-2, FPP-1, RM-1 through RM-3, and ECON-1

Electronic copies of the filing, along with the executable electronic copies of load forecasting and work papers will be delivered to the Regulatory Operations Staff ("Staff"), and the Attorney General's Bureau of Consumer Protection ("BCP") in both their Carson City and Las Vegas offices.

Consistent with the Commission's electronic filing regulations as adopted in Docket No. 07-03015, following this cover letter please find a table of contents for the complete filing. A table of contents for each volume appears on the cover page which provides the page reference for each item in the volume.

Accompanying this transmittal letter are portions of the filing that are to be kept under seal pursuant to NRS § 703.190(2) and NAC § 703.527 *et seq*. This information is contained in a sealed envelope appropriately marked, and contains the unredacted versions of the following:

Copyrighted and proprietary data. Technical Appendix LF-6 contains confidential copyrighted and proprietary data from S&P Global IHS Markit Insights. The Companies receive that data under a paid subscription.

Gas Premiums. Portions of the Companies' ESP Update contain the premiums that the Companies may be willing to pay for physical gas supplies. This confidential information is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. Disclosure of this confidential information to any third party would adversely affect the Companies' ability to obtain favorable terms from their gas suppliers.

PROMOD Reports. The PROMOD results set forth in ECON-1 (Confidential) are confidential. If made public, savvy market participants could use this information to determine Nevada Power and Sierra Pacific's marginal cost to produce energy. This information discloses key operating characteristics of the Companies' generation fleet and the Companies' views and expectations of relevant markets and their future procurement plans.

Forward Sales Procedures Manual, ESP POWER-1. The Forward Sales Procedures Manual sets forth information regarding the Companies' risk tolerances under varying conditions. This information constitutes commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets.

Coal Price Forecasts. Sierra's coal price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's views and expectations of the relevant markets. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in FPP-1 which is confidential.

Natural Gas Price Forecasts. Sierra's natural gas price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's views and expectations of the relevant markets. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in Section 3.B of the ESP Update and FPP-1.

Power Price Forecast. Sierra's power price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's views and expectations of the relevant markets. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in Section 3.B of the ESP Update and FPP-1.

Pursuant to NAC § 703.5274(1), one unredacted copy of the confidential information will be filed with the Commission's Secretary in a separate envelope stamped "confidential." Redacted versions of confidential information will be submitted for processing and posting onto the Commission's public website.

Pursuant to NAC § 703.5274(2), the Companies hereby request that the above-described information not be disclosed to the public. The Companies request that this information remain confidential for a period of five years, after which time the Commission may destroy or return the confidential information, at its convenience.

The Companies have transmitted protective agreements to the Staff and BCP so that they may be expeditiously served with the confidential information described above.

Should you have any questions regarding this filing, please contact me at (775) 834-5793 or michael.knox@nvenergy.com.

Respectfully submitted,

/s/ Michael D. Knox
Michael D. Knox
Senior Attorney

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

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CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A/ NV ENERGY** in Docket No. 22-09___ upon the persons listed below by electronic mail:

Don Lomoljo
Public Utilities Comm. of Nevada
1150 E. William Street
Carson City, NV 89701-3109
dlomoljo@puc.nv.gov

Staff Counsel Division
Public Utilities Comm. of Nevada
9075 West Diablo, Suite 250
Las Vegas, NV 89148
pucn.sc@puc.nv.gov

Attorney General's Office
Bureau of Consumer Protection
100 N. Carson St.
Carson City, NV 89701
bcpserv@ag.nv.gov

Attorney General's Office
Bureau of Consumer Protection
8945 W. Russell Road, Suite 204
Las Vegas, NV 89148
bcpserv@ag.nv.gov

DATED this 1st day of September, 2022.

/s/Lynn D'Innocenti
Lynn D'Innocenti
Senior Executive Assistant
Nevada Power Company
Sierra Pacific Power Company

APPLICATION

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Energy Supply Plan Update for period 2023-2024.	)))) /	Docket No. 22-09___

APPLICATION

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"), make this this Application for Approval of their Joint 2022 Energy Supply Plan Update (the "ESP Update") pursuant to Section 704.9506 of the Nevada Administrative Code ("NAC"). The Application is made under NAC § 704.535.

I. SUMMARY OF APPLICATION

NAC § 704.9506 requires that on or before September 1 of the first and second years after the action plan of a utility is filed, the utility shall file an update of the energy supply plan ("ESP") that will be applicable to the remaining period of its Action Plan. The Companies' last Triennial Integrated Resource Plan ("IRP") and ESP were filed in June 2021 and addressed the Action Plan period of 2022 to 2024 (See Docket No. 21-06001). Through this Application, the Companies seek the Public Utilities Commission of Nevada's ("Commission") approval and acceptance of their ESP Update for the second and third year of the Action Plan period addressed in the Companies' Triennial IRP and ESP. NAC § 704.9506(2) requires that an ESP Update be based on the most recent load forecast available at the time it is prepared. The Companies prepared an updated load forecast for this filing. The forecast for this ESP Update is suitable for making planning decisions during the ESP Update period (calendar year 2023-2024).

The Companies have a combined open power position of 1,409 MW in 2023 and 882 MW in 2024. Additionally, the Companies propose to continue their four-season laddering strategy to fill open power positions through 2024. 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. The ESP Update calls for the Companies to monitor the power portfolio on a continuous basis and to procure products only as needed.

The Companies will continue to implement the currently-approved four-season laddering strategy to procure physical gas, and seek approval for no new additional gas transportation contracts at this time. Sierra requests acceptance and approval to maintain its current natural gas transportation portfolio by renewing all existing gas transportation contracts with TransCanada Pipeline Ltd., Northwest Pipeline, Tuscarora Gas Transmission Company, and Great Basin Gas Transmission Company. The Companies propose continuing their current hedging strategy and will acquire no natural gas hedges during the ESP Update period.

The Coal Supply Plan proposes that Sierra fills Valmy Station's coal requirements via a competitive bidding for short term contracts through its request for proposals process transmitted to Sierra's list of qualified suppliers. Under this plan, Sierra will not solicit or enter into any long-term coal supply agreements.

Finally, the Companies seek approval of their risk management strategy and a finding that they have satisfied their single outstanding compliance item.

II. The Applicant

Nevada Power and Sierra are Nevada corporations and wholly-owned subsidiaries of NV Energy, Inc. Nevada Power and Sierra are public utilities as defined in NRS § 704.020, and are subject to the jurisdiction of the Commission. Nevada Power is engaged in providing electric service to the public in portions of Clark and Nye counties, Nevada pursuant to a certificate of public convenience and necessity issued by this Commission. Sierra provides electric service to the public in portions of fourteen northern Nevada counties, including the communities of Carson City, Minden, Gardnerville, Reno, Sparks, and Elko. Sierra owns and operates a certificated local distribution company engaged in the retail sale of natural gas to customers in the Reno-Sparks metropolitan area.

Sierra's primary business office is located at 6100 Neil Road in Reno, Nevada and Nevada Power's primary business office is located at 6226 West Sahara Avenue in Las Vegas, Nevada. All correspondence related to this Application should be transmitted to the Companies' counsel and to the Manager of Regulatory Services, as set forth below:

Michael Knox Senior Attorney 6100 Neil Road Reno, NV 89511 775-834-3551 michael.knox@nvenergy.com	Aaron Schaar Manager, Regulatory Services 6100 Neil Road Reno, NV 89511 775-834-5823 aaron.schaar@nvenergy.com

III. THE FILING

A. Introduction

The Commission's regulations obligate the Companies to provide an annual update to their triennial ESP.[1] This ESP Update satisfies this requirement and addresses the second and third year of the period covered by the Action Plan from the Companies' last triennial ESP (calendar year 2022-2024). The ESP Update sets forth the Companies' purchased power procurement plan (NAC § 704.9482(3)), fuel procurement plan (NAC § 704.9482(4)), and risk management strategies (NAC § 704.9482(5)). These plans and strategies govern the Companies' day-to-day operations and facilitate the provisioning of reliable electric service to customers and just and reasonable rates.

B. Elements of the Filing

The ESP Update consists of two volumes and is organized as follows:

Volume 1 – Transmittal Letter, Table of Contents, Certificate of Service, Application, Draft Notice, Testimonies and Narrative

Volume 2 – Technical Appendices LF-1 through LF-6, POWER-1, GAS-1 through GAS-2, FPP-1, RM-1 through RM-3, and ECON-1

[1] NAC § 704.9506(1).

C. Witnesses Providing Prepared Testimony in Direct Case

The Companies have prepared and filed written testimony of several witnesses to support the ESP Update. The Companies are prepared to present their witnesses in their direct case at any hearing scheduled in this matter. Specifically, the Companies intend to call the following witnesses to sponsor prepared written testimony in their direct case:

Janet Wells, Vice President of Regulatory. Ms. Wells serves as the overall policy witness, introduces the Companies' witnesses, describes the preparations of the ESP Update, and provides an overview of the ESP Update. Ms. Wells also sponsors the following Sections of the ESP Update: Section 1 ('Executive Summary"); Section 8 ("Determination of Prudence under Nevada Administrative Code ("NAC") §§ 704.9508(2) and 704.9494"), including the 2020-2021 cost-to-serve estimates for the Companies; and Section 9.A ("Commission Directives" regarding gas hedging workshops).

Ryan Atkins, Senior Director, Trading, Analytics & Operations. Mr. Atkins sponsors Section 2.C ("Energy Requirements"), Section 2.G ("Financial Gas Requirements"), Section 2.H ("Coal Requirements"), Section 4 ("Power Procurement Plan"), Section 5.A ("Physical Gas Procurement Plan"), Section 5.C ("Gas Hedging Plan") and Section 6 ("Coal Supply Plan"). Mr. Atkins also co-sponsors the portions of Technical Appendix Item FPP-1 that relate to the Companies' coal price forecast and Technical Appendix Items POWER-1. Additionally, Mr. Atkins presents an update to market capacity concerns for the action plan period.

Michael Cole, **Senior Vice President and the Chief Financial Officer and Treasurer.** Mr. Cole sponsors Section 7 ("Risk Management Strategy") of the ESP, which relates to the Risk Control organization and strategy. Mr. Cole describes the role of the Risk Control organization in managing energy supply risk. In addition, Mr.

Cole sponsors portions of Section 8 of the ESP specifically addressing the Companies' creditworthiness as well as Technical Appendix Items RM-1 through RM-3.

Sophia Hickly, Production Cost Modeling Lead. Ms. Hickly sponsors Section 2.B ("Capacity Requirement"), Section 2.E ("Gas Transportation Requirements"), and Section 2.F ("Physical Gas Requirement") related to the economic analysis that supports the physical gas requirements. Ms. Hickly also sponsors Technical Appendix items ECON-1.

Jenny Naughton, Revenue Requirements and FERC Manager. Ms. Naughton sponsors Technical Appendix Item GAS-2, which provides actual and forecasted Base Tariff Energy Rates ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") components.

Tim Pollard, Director, Load Forecasting, Research and Analytics. Mr. Pollard sponsors the ESP Update load forecast, which is found in Section 2.A ("NV Energy Electric Load Forecast") of the ESP Update narrative and Technical Appendix Items LF-1 through LF-6.

Shane Pritchard, Director, Renewable Energy & Origination. Mr. Pritchard, sponsors the Renewable Energy Planning section, Section 2.D, and an update on the progress of the White Pine Pumped Storage Hydro project, Section 9.B.

Vincent Vitiello, Gas Supply Planning Lead. Mr. Vitiello sponsors the Companies' natural gas transportation strategy, Section 5.B.

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

Zeljko Vukanovic, Market Fundamentals Lead. Mr. Vukanovic sponsors Section 3, Market Fundamentals and Price Forecasts along with Technical Appendix FPP-1, the fuel and purchased power price forecasts.

D. <u>Determination that the Elements of the ESP Update are Prudent</u>

Pursuant to NAC § 704.9508(2), the Commission reviews an ESP Update under the same standards that apply to the Commission's review of an ESP.[2] The Commission may determine that the elements of an energy supply plan update are prudent if the following criteria are met:

> (a) The energy supply plan must 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.
> (b) The energy supply plan must optimize the value of the overall supply portfolio for the utility for the benefit of its bundled retail customers.
> (c) The utility must demonstrate that the energy supply 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.[3]

The ESP Update satisfies these criteria. The Companies acknowledge that the prudence of their implementation of an approved ESP Update will be determined in a future deferred energy proceeding. In addition, pursuant to NAC § 704.9504, the Companies may deviate from an approved ESP Update "to the extent necessary to respond adequately to any significant change in circumstances not contemplated by the energy supply plan."

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[2] NAC § 704.9508(2).
[3] NAC § 704.9494.

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

IV. CONFIDENTIAL INFORMATION

The Companies request confidential treatment of a portion of the load forecast, the proposed cap on premiums to be paid for physical gas supplies, and other portions of this filing as outlined below. These requests are made pursuant to NAC § 703.7274.

Copyrighted and proprietary data. Technical Appendix IRP LF-6 contains confidential copyrighted and proprietary data from S&P Global IHS Markit Insights. The Companies receive that data under a paid subscription.

Gas Premiums. Portions of Nevada Power's Physical Gas Procurement plan contain the premiums that the Companies may be willing to pay for physical gas supplies. This confidential information is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. Disclosure of this confidential information to any third party would adversely affect the Companies' ability to obtain favorable terms from their gas suppliers.

PROMOD Reports. The PROMOD results set forth in ECON-1 (Confidential) are confidential. If made public, savvy market participants could use this information to determine the Companies' marginal cost to produce energy. This information discloses key operating characteristics of the Companies' generation fleet and the Companies' views and expectations of relevant markets and their future procurement plans. 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 by limiting their ability to foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing their bargaining leverage. Publication of this information would unfairly advantage competing buyers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of their customers.

ESP POWER-1. The Forward Sales Procedures Manual sets forth information regarding the Companies' risk tolerances under varying conditions. This information constitutes commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets. 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 foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing their bargaining leverage. Publication of this information would impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of their customers.

Coal Price Forecasts. Sierra's coal price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's views and expectations of the relevant markets. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information would impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in FPP-1 which is confidential.

Natural Gas Price Forecasts. Sierra's natural gas price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's views and expectations of the relevant markets. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information would impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in Section 3.B of the ESP Update and FPP-1.

Power Price Forecasts. Sierra's power price forecasts constitute commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses Sierra's views and expectations of the relevant markets. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage Sierra by limiting its ability to foster competition among prospective suppliers, compromising Sierra's negotiating position and reducing its bargaining leverage. Publication of this information would impair Sierra's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. This information is contained in Section 3.B of the ESP Update and FPP-1.

The "Confidential Material" envelope accompanying this Application contains a confidential and unredacted copy of each page of the ESP Update (in a sealed envelope with a copy of the first page of this Application securely fastened thereon) and with each confidential page stamped "CONFIDENTIAL AND UNREDACTED." The Companies request that the Commission maintain the confidentiality of this information for a period of no less than five years, after which the Commission may return or destroy this information, as is most convenient to the Commission.

V. REQUESTS FOR RELIEF

Nevada Power and Sierra respectfully request that pursuant to NAC § 704.9508(1), the Commission convene a hearing on this ESP Update within 60 days of the filing date, and issue an order accepting this ESP Update within 120 days and containing the following findings:

1. **Load Forecast:** A finding that the updated load forecast prepared for this ESP Update is suitable for making planning decisions during the ESP Update period (2023-2024).

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

3. **Physical Gas Procurement Plan:** Acceptance and approval of their 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 their physical gas procurement strategy is prudent.

4. **Gas Transportation Plan:** Acceptance and approval of their gas transportation plan, and an affirmative finding consistent with NAC § 704.9494(3) that their gas transportation strategy is prudent.

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

6. **Coal Procurement Plan**: Acceptance and approval of Sierra's Coal Procurement Plan, and an affirmative finding consistent with NAC § 704.9494(3) that its coal procurement strategy is prudent.

7. **Risk Management Strategy:** Acceptance and approval of their 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 utilities plan to address and balance or hedge the identified risks related to cost, price volatility and reliability. The Companies are requesting an affirmative finding consistent with NAC § 704.9494(3) that their risk management strategy is prudent.

8. **Directives:** A finding that the Companies have satisfied their obligation to continue to hold quarterly workshops with Regulatory Operations Staff and the Attorney

General's Bureau of Consumer Protection to review the implementation of the constituent elements of the ESP Update and the approved hedging strategy as contained in Commission Order dated December 2, 2020, in Docket No. 20-09002.

A finding that the Companies have satisfied their obligation to provide a status update for the pumped storage hydro project located in White Pine County, Nevada, in this ESP Update, as required by the Commission's Order dated July 13, 2022, in Docket No. 22-03024.

9. **Confidential Treatment:** Grant the Companies' request for confidential treatment of certain information filed under seal as described above.

10. **Other Relief:** Grant any other relief that the Commission deems appropriate based on the Application and the record adduced at any hearing held in this matter.

Dated and respectfully submitted this 1st day of September, 2022.

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

/s/ Michael Knox
Michael Knox
Senior Attorney
6100 Neil Road
P.O. Box 10100
Reno, Nevada 89511
Tel: 775-834-5793
Fax: 775-834-4811
Email: michael.knox@nvenergy.com

DRAFT NOTICE

PUBLIC UTILITIES COMMISSION OF NEVADA
DRAFT NOTICE
(Applications, Tariff Filings, Complaints, and Petitions)

Pursuant to Nevada Administrative Code ("NAC") 703.162, the Commission requires that a draft notice be included with all applications, tariff filings, complaints and petitions. Please complete and include **ONE COPY** of this form with your filing. (Completion of this form may require the use of more than one page.)

A title that generally describes the relief requested (see NAC 703.160(4)(a)):

> **Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for Approval of their Joint Energy Supply Plan Update for period 2023-2024.**

The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(4)(b)):

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

A brief description of the purpose of the filing or proceeding, including, without limitation, a clear and concise introductory statement that summarizes the relief requested or the type of proceeding scheduled **AND** the effect of the relief or proceeding upon consumers (see NAC 703.160(4)(c)):

> **Nevada Power and Sierra Pacific are seeking approval of their Joint Energy Supply Plan Update ("ESP Update") for calendar years 2023 and 2024, which is filed pursuant to NAC § 704.9506, and sets forth the Companies' power procurement plan, fuel procurement plan, and risk management strategy. NAC § 704.9506(1) requires that Nevada Power and Sierra Pacific file an update of the energy supply plan on or before September 1, 2022. The ESP Update includes a power procurement plan, a fuel procurement plan and risk management strategies. The Company requests that the Public Utilities Commission of Nevada approves this ESP Update and makes the determinations of prudence provided for in NAC § 704.9494 regarding each element of the plan.**

A statement indicating whether a consumer session is required to be held pursuant to Nevada Revised Statute ("NRS") 704.069(1)[1]:

> **No. A consumer session is not required by NRS § 704.069.**

If the draft notice pertains to a tariff filing, please include the tariff number **AND** the section number(s) or schedule number(s) being revised.

> **Not Applicable**

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[1] NRS 704.069 states in pertinent part:

> 1. The Commission shall conduct a consumer session to solicit comments from the public in any matter pending before the Commission pursuant to NRS 704.061 to 704.110 inclusive, in which:
> (a) A public utility has filed a general rate application, an application to recover the increased cost of purchased fuel, purchased power, or natural gas purchased for resale or an application to clear its deferred accounts; and
> (b) The changes proposed in the application will result in an increase in annual gross operating revenue, as certified by the applicant, in an amount that will exceed $50,000 or 10 percent of the applicant's annual gross operating revenue, whichever is less.

JANET WELLS

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2022 Energy Supply Plan
Docket No. 22-09___

Prepared Direct Testimony of

Janet Wells

I. INTRODUCTION

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 Regulatory for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra", and together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6100 Neil Road, Reno, Nevada 89511. 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 15 years of utility experience within the Rates and Regulatory Affairs department. 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.**

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT REGULATORY.

A. My responsibilities are to oversee the preparation of regulatory filings before the Public Utilities Commission of Nevada ("Commission") and, specifically, the work performed by the Load Research, Pricing, Regulatory Affairs and Resource Planning technical teams.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes, most recently in Docket No. 21-09031 and 21-09032, the advice letter filings to modify the Incremental Pricing Tariff. **Exhibit Wells-Direct-1** provides a full list of cases in which I have testified before the Commission.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibit:

- Exhibit Wells-Direct-1 Statement of Qualifications

II. PURPOSE OF TESTIMONY

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

A. As the 2022 Energy Supply Plan ("ESP") Update policy witness, I introduce the Companies' witnesses, describe the preparation of the ESP, and describe and give an overview of the ESP. I also sponsor the following sections in the Companies' ESP:

- Section 1 ("Executive Summary");
- Portions of Section 8 ("Determination of Prudence under Nevada Administrative Code ("NAC") §§ 704.9508(2) and 704.9494"),

including the 2022-2024 cost-to-serve estimates for the Companies; and

- Section 9 ("Commission Directives" regarding gas hedging workshops)

III. INTRODUCTION OF OTHER WITNESSES

7. 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:

Ryan Atkins, Senior Director, Trading, Analytics and Operations. Mr. Atkins sponsors Section 2.C ("Energy Requirements"), Section 2.G ("Financial Gas Requirements"), Section 2.H ("Coal Requirements"), Section 4 ("Power Procurement Plan"), Section 5.A ("Physical Gas Procurement Plan"), Section 5.C ("Gas Hedging Plan") and Section 6 ("Coal Supply Plan"). Mr. Atkins also co-sponsors the portions of Technical Appendix Item FPP-1 that relate to the Companies' coal price forecast and Technical Appendix Items POWER-1. Additionally, Mr. Atkins presents an update to market capacity concerns for the action plan period.

Michael Cole, **Senior Vice President and the Chief Financial Officer and Treasurer.** Mr. Cole sponsors Section 7 ("Risk Management Strategy") of the ESP, which relates to the Risk Control organization and strategy. Mr. Cole describes the role of the Risk Control organization in managing energy supply risk. In addition, Mr. Cole sponsors portions of Section 8 of the ESP specifically addressing the Companies' creditworthiness as well as Technical Appendix Items RM-1 through RM-3.

Sophia Hickly, Production Cost Modeling Lead. Ms. Hickly sponsors Section 2.B ("Capacity Requirement"), Section 2.E. ("Gas Transportation Requirements"), and Section 2.F ("Physical Gas Requirement") related to the economic analysis that supports the physical gas requirements. Ms. Hickly also sponsors Technical Appendix items ECON-1.

Jenny Naughton, Revenue Requirements and FERC Manager. Ms. Naughton sponsors Technical Appendix Item GAS-2, which provides actual and forecasted Base Tariff Energy Rates ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") components.

Tim Pollard, Director, Load Forecasting, Research and Analytics. Mr. Pollard sponsors the ESP Update load forecast, which is found in Section 2.A ("NV Energy Electric Load Forecast") of the ESP Update narrative and Technical Appendix Items LF-1 through LF-6.

Shane Pritchard, Director, Renewable Energy & Origination. Mr. Pritchard sponsors the Renewable Energy Planning section, Section 2.D, and an update on the progress of the White Pine Pumped Storage Hydro project, Section 9.B.

Vincent Vitiello, Gas Supply Planning Lead. Mr. Vitiello sponsors the Companies' natural gas transportation strategy, Section 5.B.

Zeljko Vukanovic, Market Fundamentals Lead. Mr. Vukanovic sponsors Section 3, Market Fundamentals and Price Forecasts along with Technical Appendix FPP-1, the fuel and purchased power price forecasts.

IV. PREPARATION OF ESP UPDATE

8. Q. HOW DO THE COMPANIES PREPARE AN ESP UPDATE?

A. The ESP is a short-term period covering the first three years of the triannual integrated resource plan ("IRP"). This filing is an update to the 2021 IRP and covers the 2023 through 2024 period. In preparation of this ESP Update, the load forecast was first updated. The Companies use the load forecast to project customers' energy needs, including appropriate planning reserve margins. Once those needs are known, the Companies then assess the options available to meet those needs. The process includes an examination of market fundamentals in the region, including the outlook for change over the planning horizon. The Companies then identify resource options such as market purchases, including the type or mix of products, NV Energy-owned resources, and long-term power purchase agreements that are available to meet identified needs. The resource options are evaluated against three criteria: 1) minimizing the cost of supply, 2) minimizing retail price volatility, and 3) maximizing the reliability of energy supply over the term of the ESP. The Companies also consider the need to comply with Nevada's Renewable Portfolio Standard ("RPS"), whether the ESP optimizes the value of the overall supply portfolio for the benefit of customers, and whether the ESP contains any feature or mechanism that would impair the restoration of the Companies' creditworthiness or would lead to a deterioration of the Companies' creditworthiness.

9. Q. HOW DO IRPS AND ESPS FIT INTO THE COMPANIES' APPROACH TO MANAGING RISK?

A. Prudent planning – embodied in IRPs, ESPs and ESP Updates – is an essential element of the Companies' risk management approach. IRPs cover long-term resource and infrastructure needs, and set forth the plans to meet customer needs over the long-term. ESPs and ESP updates address near-term resource requirements for the Action Plan period and set forth the plans and strategies to meet near-term customer needs. The Companies' approach includes adherence to the approved supply plans and the ongoing execution of these plans, including monitoring and managing the costs and risks associated with the energy supply portfolio.

10. Q. WHAT PRINCIPLES GUIDED THE COMPANIES IN THE DEVELOPMENT OF THIS ESP UPDATE?

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

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

2) **Utilize Competitive Procurement Processes**. The Companies use request for proposals ("RFPs"), or other tools, designed to produce competitive offers so that the Companies procure necessary resources in a manner that yields just and reasonable rates. RFPs provide flexibility to adjust the contracted amount based on the reasonableness of the offers that are received. An experienced team evaluates the proposals that are received, and determines the contract awards based upon price, reliability, and other

competitive factors. The Companies' procedures are designed to ensure that customers pay fair market value for the commodities that the Companies purchase on their behalf.

3) **Continuous Evaluation and Monitoring**. 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. As a further check on the costs and benefits of the approved ESP and ESP Updates throughout the implementation process, the Risk Control organization monitors the energy costs and customer value at risk against set limits on a monthly basis, and reports variances to the Risk Committee. To the extent that circumstances dictate a change in strategy, the Resource Planning organization alerts the Risk Committee, notifies the Commission's Regulatory Operations Staff ("Staff") and Attorney General's Bureau of Consumer Protection ("BCP"), and obtains appropriate approvals of such deviations where applicable.

11. Q. FOLLOWING THE EVENTS IN 2020 AND 2021 IN THE ENERGY MARKETS ASSOCIATED WITH RECORD-BREAKING HEAT THROUGHOUT THE WESTERN UNITED STATES AND WILDFIRE IMPACTS ARE THE COMPANIES TAKING ACTIONS TO MITIGATE RISK?

A. Yes. The Companies have taken several actions to mitigate risk and ensure reliable service.

First, the Companies continued to be actively involved in Docket 20-08014, the Commission's investigation to review resource adequacy and planning to ensure that electric utilities' supply of energy is sufficient to satisfy demands and maintain reliable, continuous service.

Next as described in Sections 2.A and 2.B of the ESP and in Volumes 5 and 16 of the 2021 Joint IRP, the Companies are using new trended weather load forecasts and an updated planning reserve margin ("PRM"). To further ensure resource adequacy considering market purchases commitments that were not honored by sellers in August of 2020 and July 2021 the 2021 Joint IRP and First Amendment to the 2021 Joint IRP reduced reliance on market purchases. While significant curtailments such as those experienced in 2020 and 2021 have not occurred to date in 2022, Nevada has experienced a milder summer and as described by Mr. Atkins, risk factors such as extreme weather (including drought), capacity retirements, renewable resource availability, and CAISO rule changes remain.

Finally, the Companies completed their evaluation of alternative supply side options described in the supplement to the 2020 ESP Update, filed on December 18, 2020 in Docket No. 20-12020, and the Companies proposed and received approval for upgrades to generating units and installations of grid-tied batteries as part of the 2021 Joint IRP.[1] The combustion turbine upgrades increased output, efficiency, and operational flexibility allowing the NV Energy system to benefit from a reduction of the open position and from increased operational flexibility as additional renewables are installed.

[1] The following projects have been completed for added capacity since the 2021 summer: turbine and wet compression upgrades at Higgins approximately 60 MW; turbine upgrade at Chuck Lenzie Block 1 approximately 40 MW; and the addition of a 10 MW grid-tied battery. 2022 additions include Chuck Lenzie Block 2 approximately 40 MW, Silverhawk approximately 70 MW, and Tracy approximately 36 MW. Finally in 2023 at Harry Allen approximately 45 MW. Additional capacity installed prior to summer of 2022 were Clark Peakers approximately 60 MW, Harry Allen Peakers approximately 14 MW, and Sun Peak approximately 21 MW.

Additionally, the first amendment to the 2021 Joint IRP proposed and received approval to build a 220 MW battery at Reid Gardner as well as adding 66 MW of additional capacity through upgrades to existing generation. All these adjustments, totaling over 600 MW of additional capacity to support the hour of largest open position strengthen resource reliability and reduce reliance on market purchases.

12. Q. WHAT UPDATES CAN THE COMPANIES' PROVIDE REGARDING APPROVED RENEWABLE PROJECTS CURRENTLY UNDER DEVELOPMENT?

A. To date, no project has provided formal notification that it will not proceed, although many are facing challenges associated with current market conditions and global supply chain issues. The Company is closely monitoring these projects and will provide updated information as contract obligations are either met or missed.

V. OVERVIEW OF ESP UPDATE

13. Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS IN THIS ESP UPDATE.

A. First, and most generally, the Companies ask that the Commission approve and accept the ESP Update and, pursuant to the Commission's regulations, find that the elements of the ESP Update – the purchased power procurement plan, the fuel procurement plan, and the risk management strategy – and the components of those elements are prudent.

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

Second, and more specifically, the Companies request that the Commission make the following findings:

- That the ESP Update 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 Update optimizes the value of the overall supply portfolio of the Companies for the benefit of their bundled retail customers.
- That the ESP Update 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 prepared for this ESP Update is suitable for making planning decisions during the remainder of the ESP action plan period (2023-2024).

Power Procurement/Sales Plans: Acceptance and approval of their power procurement/sales plan, and an affirmative finding consistent with NAC § 704.9494(3) that their 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.

<u>Fuel Procurement Plans:</u>[2]

Physical Gas Procurement Plan: The Companies request acceptance and approval of their 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 their physical gas procurement strategy is prudent.

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

Gas Hedging Plan: The Companies request acceptance and approval of their 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 their gas hedging strategy is prudent.

Coal Procurement Plan: The Companies request acceptance and approval of their Coal Procurement Plan, and an affirmative finding consistent with NAC § 704.9494(3) that their coal procurement strategy for the Valmy station is prudent.

<u>Risk Management Strategy:</u> The Companies request acceptance and approval of their 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

[2] The "fuel procurement plan" consists of four distinct elements, namely: the physical gas procurement plan, the gas transportation plan, the natural gas hedging plan and the coal procurement plan.

hedge the identified risks related to cost, price volatility and reliability. The Companies request an affirmative finding consistent with NAC § 704.9494(3) that their risk management strategy is prudent.

<u>Directives:</u> The Companies request a finding that they have satisfied their obligations to continue to hold bi-annual workshops with Staff and BCP and provide updates in the form of presentations to review the implementation of the constituent elements of the ESP and ESP updates, and the approved hedging strategy as contained in the Commission's order dated October 17, 2019 in Docket No. 19-08034.

The Companies request a finding that they have satisfied their obligations to provide an update on the White Pine Pumped Storage Hydro project as agreed upon in the stipulation in Docket No. 21-03024.

14. Q. DOES THIS ESP BALANCE THE OBJECTIVES OF MINIMIZING THE COST OF SUPPLY, MINIMIZING RETAIL PRICE VOLATILITY, AND MAXIMIZING THE RELIABILITY OF SUPPLY OVER THE TERM OF THE ACTION PERIOD?

A. Yes, it does. The strategies set forth herein minimize the cost of supply and retail price volatility and maximize reliability by dispatching the Companies' lowest-cost available resources; by utilizing competitive solicitations to secure the most competitive sources of short-term supply when appropriate; and by procuring resources consistent with its approved risk management strategies.

15. Q. DOES THIS ESP UPDATE OPTIMIZE THE VALUE OF THE OVERALL SUPPLY PORTFOLIO FOR THE COMPANIES' CUSTOMERS?

A. Yes, it does. Mr. Atkins addresses this issue in further detail. The ESP Update allows flexibility to optimize the benefits of owned resources by making sales into the wholesale energy market, to the extent that the resources are not expected to be needed to serve load. The ESP Update also provides for continuous monitoring of the strategies and is robust enough to provide the flexibility to modify the approved strategies as changing conditions may warrant.

VI. COST TO SERVE

16. Q. PLEASE DEFINE THE TERM COST-TO-SERVE AS IT IS UTILIZED IN THIS ESP UPDATE.

A. Cost-to-serve represents the estimated annual fuel and purchased power costs of the Companies and is derived from the production cost simulation model. These estimates are used in calculating forecasted BTER and DEAA rates. Ms. Naughton sponsors the forecast of the BTERs and DEAA rates.

17. Q. FOR WHAT SCENARIOS DID THE COMPANIES DEVELOP COST-TO-SERVE ESTIMATES?

A. Cost-to-serve estimates were prepared assuming base, low, and high fuel and purchased power costs.

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

A. Yes, it does.

Janet C. Wells
Vice President of Regulatory
Rates and Regulatory Affairs
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-4135

Mrs. Wells has been an employee of NV Energy for fifteen years and her time at the company includes her previous positions as 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 Regulatory. Her current responsibilities are focused on the analytical and strategic approaches to regulatory issues and filings.

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 Regulatory
May 2022 to Present

- Oversee the preparation of regulatory filings before the Public Utilities Commission of Nevada and specifically the Load Research, Pricing, Regulatory Affairs and Resource Planning 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 2013

- 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

<u>Other Related Employment</u>
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 Public Utilities Commissions
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, and 21-09032.

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

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: September 1, 2022

Janet Wells

JANET WELLS

RYAN ATKINS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2022 Energy Supply Plan
Docket No. 22-09___

Prepared Direct Testimony of

Ryan Atkins

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

A. My name is Ryan Atkins. I am the Senior Director of Trading, Analytics & Operations for Sierra Pacific Power Company d/b/a NV Energy ("Sierra") and Nevada Power Company d/b/a NV Energy ("Nevada Power" and, together with Sierra, the "Companies"). I work primarily out of Nevada Power's office at 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. My professional experience includes more than 15 years in the energy industry. This includes experience in natural gas trading, real-time power trading, day-ahead power trading, and term power trading. More details regarding my background and experience are provided in **Exhibit Atkins-Direct-1.**

3. Q. WHAT ARE YOUR RESPONSIBILITIES AS SENIOR DIRECTOR, TRADING, ANALYTICS AND OPERATIONS?

A. In my role as Senior Director of Trading, Analytics and Operations, I am responsible for directing the development and execution of strategies aimed at maximizing the value of the Companies' portfolio of energy supply resources. This includes the development of trading analytics to support energy marketing and origination activities; short-term and long-term trading activities related to power, gas, and coal; ensuring the economic dispatch of the Companies' generation facilities; and managing the trading and market functions related to the Western Energy Imbalance Market.

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

A. Yes. I have previously testified before the Commission in deferred energy proceedings, energy supply plan filings, and integrated resource plan filings.

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

A. I sponsor Section 2.C ("Energy Requirements"), Section 2.G ("Financial Gas Requirements"), Section 2.H ("Coal Requirements"), Section 4 ("Power Procurement Plan"), Section 5.A ("Physical Gas Procurement Plan"), Section 5.C ("Gas Hedging Plan") and Section 6 ("Coal Supply Plan"). I also co-sponsor the portions of Technical Appendix Item FPP-1 that relate to the Companies' coal price forecast and Technical Appendix Items POWER-1. In addition, I present an update to market capacity concerns for the Companies' 2022 Joint Energy Supply Plan Update ("ESP Update") for the 2023-2024 action plan period. This is being made in response to the evolving Western energy market, including emergent concerns regarding the uncertain availability of regional market capacity.

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

A. Yes, I am sponsoring the following Technical Appendix Item:

ESP POWER-1 –Forward Power Sales Procedures Manual (Confidential).

7. Q. WHY IS ESP POWER-1 BEING PROVIDED AS CONFIDENTIAL?

A. The Forward Sales Procedures Manual sets forth information regarding the Companies' risk tolerances under varying conditions. This information constitutes commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets. 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 foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing their bargaining leverage. Publication of this information would impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of their customers.

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

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

9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP") 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 with them.

10. 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 request for proposals ("RFP") 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 Atkins Direct-2**.

Table Atkins Direct-2
Percentage of open power position to be closed in each procurement period

Incremental transaction	Delivery		
	Summer 2022	Summer 2023	Summer 2024
Q3 2020	25%		
Q1 2021	25%		
Q3 2021	25%	25%	
Q1 2022	25%	25%	
Q3 2022		25%	25%
Q1 2023		25%	25%
Q3 2023			25%
Q1 2024			25%
Sum	100%	100%	100%

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.

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

A. Yes. The Companies have some concerns regarding their ability to obtain sufficient energy to fill any additional open positions that may occur during the ESP forecast period due to unanticipated increases in energy demand and/or shortages in market supply. As evidenced by the extreme weather events in the summer of 2020 and 2021, if a large geographical area throughout the west experiences a prolonged heat wave or major wildfire, it is possible that available firm energy products will be limited or unavailable.

12. Q. WHAT MARKET CONCERNS HAVE EMERGED SINCE THE SUMMER OF 2020?

A. Resource adequacy risks for the state of Nevada and the Western region as a whole have manifested themselves since the summer of 2020. Risks for the Western region have changed for a number of reasons including shifts in weather and a rapidly changing resource mix. Weather has grown more extreme across the region, resource variability has increased, and continued drought conditions have led to supply reductions from numerous hydroelectric power plants. In addition, there has been record wildfire activity including the Bootleg Fire in July 2021 that resulted in the loss of more than 5,500 MW of transmission capacity from the Pacific AC and DC interties. The California Independent System Operator's ("CAISO") rule changes, discussed further below, have cast additional uncertainty into the market. Coal supply and delivery has also become a significant challenge for the entire region as demand for coal has increased worldwide which has left coal mines and railroads unable to catch up to production and transportation needs. All these factors have led to reduced market liquidity and increased market prices.

13. Q. HAVE SUPPLY CURTAILMENTS CREATED ADDED RISK FOR THE COMPANIES?

A. Yes. The Companies have experienced two major supply curtailment events that have led to emergency conditions. On August 18, 2020, the Companies experienced significant curtailments with the largest curtailment occurring in hour ending 19 with curtailments of 1,243 MW. This led to the Companies entering a Level 3 Energy Emergency Alert ("EEA"), which is the highest level of emergency and means load shed is imminent. On July 9, 2021, the Companies experienced significant curtailments again. The largest curtailment occurred in hour ending 20 with curtailments totaling 1,406 MW. This once again led to the Companies entering an EEA Level 3 situation. Supply curtailments of this size highlight the risk of relying so heavily on market purchases. Both of these events occurred on days on which Nevada and many other Western states experienced record or near record temperatures.

14. Q. ARE THESE CONCERNS EXPECTED TO CONTINUE GOING FORWARD?

A. Yes. Climate-related incidents such as those on August 18, 2020, and July 9, 2021, no longer appear to be isolated incidents. While Nevada saw a milder summer in 2022, the United States as a whole faced record temperatures that highlight the growing risk of extreme weather events. July 2022 was the third-hottest July on record for the U.S. according to scientists from NOAA's National Centers for Environmental Information. Texas reported its hottest summer on record. Portland and Seattle both set new heat duration records in July. As mentioned in the IRP First Amendment, continued drought conditions have led to supply reductions from numerous hydroelectric power plants. Specifically in California and the Desert Southwest Region, water levels remain critically low and continue to drop which leads to the likely scenario that output from major hydroelectric facilities in the West such as Hoover, Glen Canyon and Hyatt will be reduced or eliminated in the near future, adding to the already existing market uncertainty. In addition, many fossil and other baseload power plant retirements have recently occurred or are scheduled in the near-term West-wide. As stated in the First Amendment to the 2021 Joint

IRP ("First Amendment"), WECC reports indicate fossil and nuclear retirements totaling 4,266 MW in California, 1,561 MW in the Desert Southwest, and 2,590 MW in the Central Northwest Power Pool between now and the end of 2025.[1] At the same time, a June 2021 California Public Utilities Commission order in Docket No. R.20-05-003 required procurement of 11,500 MW of specifically non-fossil resources by the end of 2026.[2] Not only could these changes dramatically affect the resource mix in the region and the availability of market capacity but, in addition, many recent developments are conspiring to delay planned new renewable resources in the West and across the United States.

15. Q. WILL CAISO RULE CHANGES INCREASE THE COMPANIES' MARKET RISK GOING FORWARD?

A. Yes. Market concerns continue to be compounded by the CAISO's change in day-ahead export priorities implemented in the summer of 2021, and its ongoing Wheel Through Initiative. The change in export priorities allows CAISO to adjust day-ahead export schedules to zero with potentially less than an hour's notice on whether the energy will flow. The changes to Wheel Through priorities allow CAISO to prioritize use of Northwest imports to serve CAISO load, precluding short-term (less than 45-day) firm energy from being wheeled through California. These two items impact both the Companies and Open Access Transmission Tariff ("OATT") customers in Nevada. FERC issued an order extending the wheel-through policies approved

[1] *See* WECC, *Western Assessment of Resource Adequacy Subregional Spotlight: Northwest Power Pool – Central*, February 26, 2021; WECC, *Western Assessment of Resource Adequacy Subregional Spotlight: California and Mexico (CAMX)*, February 12, 2021; WECC, *Western Assessment of Resource Adequacy Subregional Spotlight: Desert Southwest (DSW)*, January 29, 2021.

[2] *See* California Public Utilities Commission, Press Release, "*CPUC Orders Historic Clean Energy Procurement to Ensure Electric Grid Reliability and Meet Climate Goals,*" available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K478/389478892.PDF.

for the summer of 2021 through May of 2024 and directed CAISO to report on progress towards a long-term approach. CAISO issued their straw proposal on July 29, 2022 with a final proposal not expected to be ready until February 2023. Accordingly, there is significant uncertainty as to what wheel-through rules will be adopted and, most significantly, what will be the amount of transmission capacity CAISO will claim on behalf of its "native load." Both of these items add significant risk to the market as a whole as the liquidity in the real-time hourly power market has been reduced significantly as more entities have joined the Energy Imbalance Market ("EIM").

16. Q. PLEASE DESCRIBE THE COMPANIES' PHYSICAL GAS PROCUREMENT PLAN.

A. Section 5.A of the ESP summarizes the Companies' physical gas procurement plan. The Companies are requesting acceptance and approval of their plan to continue to procure physical gas using the four-season laddering strategy originally approved by the Commission in Docket No. 09-09001, and most recently reaffirmed by the Commission in Docket No. 21-06001. 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. Physical gas volumes are to be procured at indexed prices, subject to a per-million Btu cap on the premium. The per-million Btu cap may be exceeded with prior approval from the Risk Committee. However, if the Companies exceed the premium cap, and the procured gas that exceeded the premium cap is not the least cost supply alternative, the Companies will provide written notice to the Staff and the BCP. 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.

17. Q. DOES SIERRA CURRENTLY HAVE ANY COAL SUPPLY COMMITMENTS FOR VALMY FOR THE ESP PERIOD?

A. Yes. Sierra currently has coal purchase agreements in place to provide enough supply through the summer of 2023. Qualified coal sources for North Valmy Station Units 1 and 2 include mines located in Central Utah, Western Colorado, and Southern Wyoming. Coal is delivered under Sierra and Idaho Power Company's Rail Transportation Services Agreement with Union Pacific Railroad Company.

18. Q. PLEASE SUMMARIZE THE RECOMMENDED COAL SUPPLY PLAN FOR VALMY.

A. Sierra recommends filling Valmy's coal requirements with short term supply contracts and competitive bidding through its standard RFP process. Sierra plans to employ this process to provide coal supplies to support Valmy's planned operations. Sierra will monitor Valmy's unit operations, coal stockpile levels, coal burn forecast updates, and scheduled must run conditions during the periods outside the summer season to assess the requirement for additional coal. In the event incremental quantities of coal should be required, Sierra would rely on short-term purchases acquired via its RFP process to supply needed quantities of coal.

19. Q. IN PROCURING COAL THROUGH ITS RFP PROCESS, DOES SIERRA EMPHASIZE COAL QUALITY?

A. Yes. In line with the goal of providing coal shipments that enable the plant to operate Valmy efficiently while meeting all required environmental regulations, coal quality parameters of all candidate coal sources are screened and reviewed with the plant.

20. Q. WHAT IS PORTFOLIO OPTIMIZATION?

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

21. Q. DO THE COMPANIES OPTIMIZE THEIR RESOURCE PORTFOLIOS?

A. Yes. The Companies engage in short-term (*i.e.*, less than one month) and forward (*i.e.*, greater than one month) purchases of power and natural gas when economic or as needed to serve native load. The Companies also engage in sales of power and natural gas to the extent that available resources are not expected to be needed to serve customer load. They also engage in sales of natural gas transportation capacity (*i.e.*, capacity release) that is not expected to be needed to serve their gas requirements. The Companies further optimize their respective power portfolio through participation in the EIM operated by CAISO"). The Companies began participating in the EIM on December 1, 2015.

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

22. Q. PLEASE DESCRIBE THE POTENTIAL BENEFITS AND RISKS TO THE COMPANIES' CUSTOMERS ASSOCIATED WITH MAKING FORWARD SALES.

A. Forward sales of power from company-owned resources that are not expected to be needed to serve native load during periods of the year can provide revenues for the benefit of customers (through the deferred energy accounting mechanism). The revenues realized from forward sales can be higher or lower than those from short-term sales depending upon market conditions. However, forward sales can also create risk by increasing the likelihood of having to replace the resources that have been sold into the forward market if load requirements increase or generation resources are not available.

23. Q. HOW DO THE COMPANIES PROPOSE TO OPTIMIZE THEIR PORTFOLIOS FOR THE BENEFIT OF CUSTOMERS DURING THE ESP PERIOD?

A. The Companies propose to continue using a mix of short-term and forward sales as part of their portfolio optimization strategy. The Companies will continue their existing practices of making sales of power, natural gas, and natural gas transport capacity to the extent that resources are not expected to be needed to serve their native load.

24. Q. WILL THE COMPANIES CONTINUOUSLY REVIEW THE PORTFOLIO OPTIMIZATION STRATEGY IN LIGHT OF CHANGING MARKET CONDITIONS?

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

25. Q. PLEASE BRIEFLY DESCRIBE THE 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.

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

A. Yes.

STATEMENT OF QUALIFICATIONS

Ryan Atkins
6226 W. Sahara Ave.
Las Vegas, NV 89146
Ryan.atkins@nvenergy.com
(702) 402-1788

PROFESSIONAL EXPERIENCE

NV Energy, Las Vegas, NV
Senior Director of Trading, Analytics and Operations, April 2022 – Current
- Oversee the development and execution of strategies aimed at ensuring resource adequacy while maximizing the value of the Companies' portfolio of energy supply resources.

Director, Trading Analytics and Operations, February 2021 – April 2022
- Directed the creation and implementation of new trading and operations strategies aimed at improving Company performance

Director, Process Improvement, May 2018 – February 2021
- Directed team in charge of business optimization and innovation efforts including automation, process mining, and benchmarking.

Project Manager, Forward Trading, August 2017 – May 2018
- Optimized NV Energy generation portfolio and executed long term power transactions consistent with the Company's risk management guidelines.

Senior Power Trader, May 2013 – August 2017
- Optimized NV Energy generation portfolio and executed day-ahead power transactions consistent with the Company's risk management guidelines.

Iberdrola Renewables, Portland, OR
Real-Time Power Trader, September 2011 – May 2013
- Executed short-term power transactions to optimize Iberdrola's western energy fleet of wind, hydro, and thermal generation.

NV Energy, Las Vegas, NV
Gas Trader, June 2010 – September 2011
- Optimized NV Energy's gas supply and transport portfolio consistent with the Company's risk management guidelines.

Real-Time Power Trader, August 2007 – June 2010
- Optimized NV Energy generation portfolio on an hour to hour basis and executed short-term hourly power transactions consistent with the Company's risk management guidelines.

EDUCATION

University of Idaho, Moscow, ID
Bachelor of Science, History, 2007

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

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, RYAN ATKINS, 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: September 1, 2022

Ryan Atkins
RYAN ATKINS

MICHAEL COLE

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2022 Energy Supply Plan
Docket No. 22-09___

Prepared Direct Testimony of

Michael Cole

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

A. My name is Michael Cole and I am a Senior Vice President and the Chief Financial Officer and Treasurer for NV Energy, Inc.; Nevada Power Company d/b/a NV Energy ("Nevada Power"); and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company," 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.

A. I joined the Companies in 2015 as Treasurer and became the Chief Financial Officer in 2018. Prior to joining the Companies, I was the Treasurer for two global manufacturing companies and for Aquila, Inc., an electric and natural gas utility based in Kansas City, Missouri. I worked previously at Standard and Poor's Ratings Group, the Maine Public Utilities Commission, and the Illinois Commerce Commission. I have undergraduate 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 is provided as **Exhibit Cole-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS SENIOR VICE PRESIDENT AND CHIEF FINANCIAL OFFICER AND TREASURER.

A. As Senior Vice President, Chief Financial Officer and Treasurer, my primary responsibilities include leadership and oversight of the accounting, tax, financial planning, internal audit, treasury, credit, and risk related functions. With input from other members of the Company's leadership team, I direct the Companies' financial policies, including the financing activities and capital structure strategies for the Companies.

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

A. Yes. I have previously testified before the Commission in integrated resource plans ("IRP"), energy supply plans ("ESP"), general rate cases ("GRC") and financing dockets. Most recently, I provided testimony in Docket No. 22-006014 (the Application by Sierra Pacific Power Company d/b/a NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers).

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

A. Yes, I sponsor the following exhibit:

Exhibit Cole-Direct-1 – Statement of qualifications

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

6. 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' 2022 ESP Update, which covers the three year period from 2022 through 2024. I sponsor the following Technical Appendices:

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

7. Q. PLEASE DESCRIBE THE POLICIES THAT GOVERN THE COMPANIES' RISK CONTROL FUNCTION.

A. The Companies' risk control policies are as follows:

- ESP-RM-1: <u>Risk Management and Control Policy</u> is the Companies' umbrella document that defines corporate risks, describes the management of that risk, and creates a governance structure (including the Risk Committee) to oversee policy implementation and adherence;
- ESP-RM-2: <u>Energy Risk Management and Control Policy</u> relates specifically to physical and financial transactions related to energy procurement, sales, and hedging. This policy establishes governance structures, authorized signatories, risk control thresholds, and compliance, among other items; and
- ESP-RM-3: <u>Credit Risk Management and Control Policy</u> provides an overview of the Companies' definition and management of risk created by a counterparty's inability or unwillingness to fulfill its contractual obligations.

8. Q. PLEASE DESCRIBE THE COMPANIES' RISK MANAGEMENT FUNCTION AND CONTROL STRUCTURE.

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

1) **Risk Committee.** The Risk Committee is the executive team responsible for the overall policy direction and administration of the Companies' integrated risk control activities. The Risk Committee serves as the mechanism through which the executive management team is kept apprised of inherent risks. The Risk Committee is also responsible for monitoring risk management and control efforts relative to fuel and wholesale power. The members of the Risk Committee are listed in the Risk Management and Control Policy (See ESP-RM-1, Section V, subsection B).

2) **Risk Control**. The Risk Control function is responsible for monitoring compliance with established risk policies and associated procedures, including the approved ESP. Risk Control 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 timely fulfill its financial or physical obligations to the Companies because of the counterparty's financial condition. Credit Risk Management generally is responsible for credit risk management activities as they apply to energy supply.

4) **Energy Supply**. Energy Supply, under direction of the Senior Vice President-Energy Supply, is responsible for the generation production, delivery and optimization of fuel and wholesale power transactions.

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

9. Q. WHAT ARE THE RISK COMMITTEE'S ENERGY SUPPLY RELATED RESPONSIBILITIES?

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

- 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 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 or ESP Updates prior to the submission for approval of such transactions 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.

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

A. Three types of risk control metrics are utilized: transaction approval metrics, portfolio risk metrics, and credit risk metrics.

11. Q. **PLEASE DESCRIBE THE TRANSACTION APPROVAL METRICS THAT ARE USED TO ASSIST THE RISK COMMITTEE IN EVALUATING THE COMPANIES' PORTFOLIOS.**

A. The transaction approval metrics control the values of contracts that authorized personnel are allowed to execute. Total dollar value of the contract is tracked and reported.

12. Q. **PLEASE DESCRIBE THE PORTFOLIO RISK METRICS THAT ARE USED TO ASSIST THE RISK COMMITTEE IN EVALUATING THE COMPANIES' PORTFOLIOS.**

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

1) **Test Period Mark-to-Base**. Monthly differences between fuel and purchased power costs and Base Tariff Energy Rate revenues are deferred. Mark-to-Base provides an estimate of such deferrals for the current deferral period. Mark-to-Base is determined using actual expenditures to date, committed expenditures for the balance of the deferral period, and expected expenditures for uncommitted purchases. The policy triggers notifications if significant changes in Mark-to-Base are experienced on either a cumulative basis or on a month-to-month basis.

2) **Value-at-Risk**. Value-at-Risk serves as a gauge of market exposure, summarizing the total market risk on the Companies' fuel and purchased power costs. As measured by the Companies, 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 a useful tool in determining liquidity requirements and is referred to as cash flow at risk when used in this context. The Energy Risk Management and Control Policy triggers notifications if Value-at-Risk exceeds certain levels. 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 projection. 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 costs 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. A distribution of possible forward price outcomes is then generated and standard statistical methods are applied to evaluate portfolio impacts at various confidence intervals.

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

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

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

14. Q. PLEASE DESCRIBE THE RISK CONTROL FUNCTION.

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

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.

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 Assistant Treasurer 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
- 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.

19. Q. WHAT HAPPENS IF A COUNTERPARTY'S CREDIT IS DOWNGRADED AFTER A CONTRACT IS SIGNED?

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

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

A. The Energy Supply organization manages energy risk by purchasing and selling financial instruments and physical products in accordance with an approved ESP. The ESP and ESP Updates are reviewed on an ongoing basis and updated at least annually. Material changes in the data or assumptions underlying the approved ESP, which may also require a change in strategy, are promptly reported to the Risk Committee by Resource Planning & Analysis. The Resource Planning & Analysis organization is addressed in more detail by Janet Wells, Vice President Regulatory.

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

A. Section 8 of the 2022 ESP addresses the three criteria set forth in Nevada Administrative Code, section 704.9494, which are to be applied by the Commission in making a determination that the ESP is prudent:

- The ESP Update 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 Update optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.
- The ESP Update 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 May 20, 2021, Moody's Investors Service affirmed the credit ratings and stable outlooks for Nevada Power and Sierra. The Issuer Ratings for Nevada Power and Sierra were affirmed at 'Baa1', and the senior secured debt ratings were affirmed at 'A2'.

Standard & Poor's Ratings Services last published a review of Nevada Power and Sierra's credit on April 11, 2022. In those reports, the credit ratings and stable outlooks for Nevada Power and Sierra were affirmed. The Issuer Credit Ratings for Nevada Power and Sierra were affirmed at 'A', and the senior secured debt ratings were affirmed at 'A+'. Table Cole-Direct 1 below shows each rating for each respective company.

TABLE COLE DIRECT-1

	S&P – STABLE		Moody's - STABLE	
	Issuer Credit Rating	Senior Secured Rating	Issuer Rating	Senior Secured Rating
Nevada Power	A	A+	Baa1	A2
Sierra	A	A+	Baa1	A2

Following the Companies' filing with the Commission on March 21, 2022, of their Joint Application to merge (Docket No. 22-03028), the two rating agencies stated that they generally viewed the merger, if approved, as a positive credit development.

23. Q. **DOES THE 2022 ESP UPDATE 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. The credit ratings assigned to Nevada Power and Sierra by Moody's following completion of the 2013 acquisition have remained unchanged. Standard & Poor's revised their rating methodology in 2016 which resulted in Nevada Power and Sierra's credit ratings being raised above the ratings assigned by Standard & Poor's to these entities at the time of the 2013 acquisition. However, despite credit rating stability, the Companies' creditworthiness should not be taken for granted.

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.

24. Q. THE 2022 ESP UPDATE 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; however, significant under collection of fuel and purchase power costs due to increasing natural gas prices and the limitations of the recovery mechanism can have 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. The recent increases in the deferred energy balances with July 31, 2022 balances totaling approximately $629.0 million has required additional funding mechanisms (such as equity contributions and bank term loans) to fund these under collections. The Companies' have strived to fund these under collected fuel and purchase power balances in a manner that reduces the negative impact on each company's creditworthiness.

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

A. Yes.

MICHAEL COLE
CHIEF FINANCIAL OFFICER
NV Energy, Inc.
6226 West Sahara Avenue
Las Vegas, NV 89151
(702) 402-5622

SUMMARY

Michael Cole has been with NV Energy since August 2015, and has approximately 25 years of experience in corporate finance, treasury operations, and corporate development. In addition, Mr. Cole has about 20 years of diverse utility experience including Aquila, Inc., Standard & Poor's Ratings Group, Maine Public Utilities Commission, and the Illinois Commerce Commission. Prior to joining NV Energy, Mr. Cole was the Treasurer for two separate, private-equity owned global manufacturing companies.

At NV Energy, Mr. Cole has primary responsibility for all accounting, finance, treasury, and risk control activities.

EMPLOYMENT

NV Energy, Inc. – Senior Vice President, Chief Financial Officer and Treasurer, Las Vegas NV (5 years)

WireCo World Group, Inc. – Vice President & Treasurer, Kansas City MO (2 years)

Polymer Group, Inc. – Treasurer, Charlotte NC (2 years)

The Calvin Group – Principal, Kansas City MO (2 years)

Aquila, Inc. (f/k/a UtiliCorp United, Inc.) – Treasurer & Vice President Finance (previous positions included Director - Corporate Development and Assistant Treasurer - International Finance), Kansas City MO (11 years)

Standard & Poor's Ratings Group – Associate Director Utilities, New York NY (3 years)

Maine Public Utilities Commission – Senior Financial Analyst, August ME (1 year)

Illinois Commerce Commission – Financial/Management Analyst, Springfield IL (5 years)

EDUCATION

Masters of Business Administration – Finance (Western Illinois University, Macomb IL)
Bachelor of Business – Finance (Western Illinois University, Macomb IL)

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, MICHAEL COLE, 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: September 1, 2022

MICHAEL COLE

SOPHIA HICKLY

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2022 Energy Supply Plan
Docket No. 22-09___

Prepared Direct Testimony of

Sophia Hickly

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

A. My name is Sophia Hickly. My current position is Production Cost Modeling 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" or "NV Energy"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada, 89146. I am filing testimony on behalf of the Companies.

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

A. My professional experience includes more than 16 years in the utility industry. I have been employed by the Companies since 2006 and have served as Production Cost Modeling Lead since December 2019. In addition to my current role in Resource Planning and Analysis, I also served as a Senior Power Trader and a Senior Power & Gas Trading Specialist at NV Energy. I have a Master of Business Administration with an emphasis in Finance. The details of my background and experience are provided in **Exhibit Hickly-Direct-1.**

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

A. As Production Cost Modeling Lead, I am responsible for developing and managing production cost models and tools to provide reports of energy usage, costs, and revenues. I assess NV Energy's short term energy needs and lead various supply management activities including developing open capacity positions consistent with regulatory requirements and NV Energy's goals and objectives.

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

A. No.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibit:

Exhibit Hickly-Direct-1 Statement of Qualifications

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

A. I sponsor the following sections in the Companies' Energy Supply Plan ("ESP") update:

- Section 2.B ("Capacity Requirements")
- Section 2.E ("Gas Transportation Requirements")
- Section 2.F ("Physical Gas Requirements")

- Technical Appendix items ECON-1

7. 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, 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 Companies' system) and external power contracts (outside 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.

Next, the Companies utilize a production cost model, "PROMOD."[1] PROMOD simulates the operation of the electric system and computes production costs (fuel, purchase power, variable and fixed costs to operate) 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 used PROMOD to calculate the average daily gas requirements as illustrated in Figures ESP-15 and ESP-16, in Section 2.F ("Physical Gas Requirements").

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[1] PROMOD is a proprietary software product that the Companies license from ABB Group.

The Companies also conduct scenario analysis under the low, base, and high fuel and purchased power price forecasts. The Companies then calculated the projected Base Tariff Energy Rates ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") rates for 2023-2024 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 and sponsored by Ms. Jenny Naughton.

An additional production cost model sensitivity was also used to evaluate the system reliability and projected firm gas transportation needs for northern and southern generation plants, and Sierra's LDC. The result of this analysis is presented in Section 2.E ("Gas Transportation Requirements") and sponsored by Mr. Vincent Vitiello.

8. Q. WERE THERE ANY NOTEWORTHY UPDATES TO KEY MODELING ASSUMPTIONS USED IN THE ECONOMIC ANALYSIS?

A. Yes, in addition to the annual updates to model inputs, the following items were approved in the 2021 Integrated Resource plan, Docket No. 21-06001: 1) increase to the planning reserve margin ("PRM"), 2) the use of new trended weather load forecasts, and 3) the ability to close the largest open capacity position in the later evening hours rather than at the peak load hour.

9. Q. WHY DID THE COMPANIES MODIFY THE PLANNING PROCESSES TO CLOSE THE LARGEST OPEN CAPACITY POSITION?

A. Due to the development of portfolios with large quantities of variable renewable resources in which available resources drop rapidly in the evening hours, a new paradigm is engaged for evaluation of the hour with the largest open position in addition to the traditional evaluation of the peak load hour to ensure reliability. Traditionally, these two hours were one and the same with respect to the size of the open capacity, but with increasing amounts of renewables, the later evening hours are showing significantly larger open positions. This paradigm shift will increase reliability and reduce risk of being reliant on short-term power markets in the evening hours.

10. 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/or trade secret information that derives independent economic value from not being generally known. Disclosure of this confidential information to any third party would adversely affect the Companies' ability to obtain favorable terms from their fuel and purchase power suppliers.

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

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

12. 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.

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

A. Yes, it does.

STATEMENT OF QUALIFICATIONS

SOPHIA HICKLY
6226 W. Sahara Ave.
Las Vegas Nevada 89146
(702) 402-5885

EDUCATION

University of Nevada at Las Vegas
Master of Business Administration – Emphasis in Finance
Bachelor of Science in Finance

PROFESSIONAL EXPERIENCE

NV ENERGY - Las Vegas, Nevada (February 2006 to Present)

Production Cost Modeling Lead, Resource Planning and Analysis, December 2019 – Present

- Provides lead analytical support for the Energy Supply Plans ("ESP"), internal budgeting, and monthly energy supply risk analysis by evaluating, structuring, and selecting production cost modeling simulation analyses to provide accurate cost optimization, including energy production costs, energy usage, and economic analysis.

Senior Power and Gas Trading Specialist, Resource Optimization, August 2018 – December 2019

- Performed production cost modeling, strategic evaluations, and ad hoc analysis for optimizing assets and reducing risks associated with the resource portfolio and wholesale market activities. Led the development, tracking, and evaluation of performance metrics associated with market operations and trading analytics.

Senior Power Trader – Gen Desk, Resource Optimization, June 2015 – August 2018

- Facilitated power trading activities through the strategic development of hourly transaction plans and capacity position reporting. Evaluated and determined optimal utilization of available energy resources in response to changing operating conditions, power and gas markets and contractual obligations on a real-time basis.

Power & Gas Trading Strategist, Resource Optimization, February 2011 – June 2015

- Developed daily and forward trading strategies for energy marketing. Established pricing for wholesale sales and purchase transactions.

Power Trader, Resource Optimization, February 2006 – February 2011

- Optimized NV Energy portfolio and engaged in wholesale buying and selling of electric energy and acquisition of transmission capacity to facilitate the physical delivery.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, SOPHIA HICKLY, 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: September 1, 2022

SOPHIA HICKLY

JENNY NAUGHTON

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2022 Energy Supply Plan
Docket No. 22-09___

Prepared Direct Testimony of

Jenny Naughton

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

A. My name is Jenny Naughton. My current position is Revenue Requirement and FERC Manager for Nevada Power d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies"). My business address is 6100 Neil Road in Reno, NV. I am filing testimony on behalf of the Companies.

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

A. I hold a Bachelor of Science degree in Finance, with an emphasis in Accounting, from the University of Nevada, Reno. I joined NV Energy in 2017 providing comprehensive rate analysis and support for our managed substantial energy use customers in the Major Accounts department. Most recently, I was a Pricing Specialist in the Regulatory Pricing and Economic Analysis department, for which I completed the Customer Weighting Factor Study ("CWFS"), and assumed the role of Revenue Requirement and FERC

Manager in March 2022. More details regarding my professional background and experience are set forth in **Exhibit Naughton Direct - 1**.

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

A. Yes. Most recently, I provided testimony to the Commission in Sierra's General Rate Case proceeding, Docket No. 22-06014, where I discussed the CWFS.

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

A. I sponsor Technical Appendix GAS-2, which reflects actual and forecasted Base Tariff Energy Rate ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") components as well as the estimated carrying charges under the gas hedging plan for the 2023-2024 action plan period.

5. Q. DID YOU PREPARE FORECASTED BTERs AND DEAAs?

A. Yes. I prepared the forecasted BTERs and DEAAs, assuming base, low, and high fuel and purchased power costs, for the gas hedging plan. No hedges are proposed. A summary of the actual and forecasted BTERs and DEAAs is provided in Technical Appendix GAS-2, pages 1 and 3 for Nevada Power and Sierra respectively.

6. Q. HOW WERE THE FORECASTED BTERS AND DEAAS CALCULATED?

A. Base, low and high fuel and purchased power price forecasts were prepared by Ms. Sophia Hickly and are presented in Technical Appendix MF-1. These forecasts were used in the PROMOD model to estimate the total cost to serve. The estimates generated by PROMOD, which are also sponsored by Ms. Hickly were used to forecast BTERs and DEAAs through the end of 2024 under base, low and high price scenarios.

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

A. Figures Naughton-Direct-1 and Naughton-Direct-2 reflect the combined Nevada Power 2023-2024 forecasted residential and non-residential BTERs and DEAAs for the plan.

Figure Naughton-Direct-1

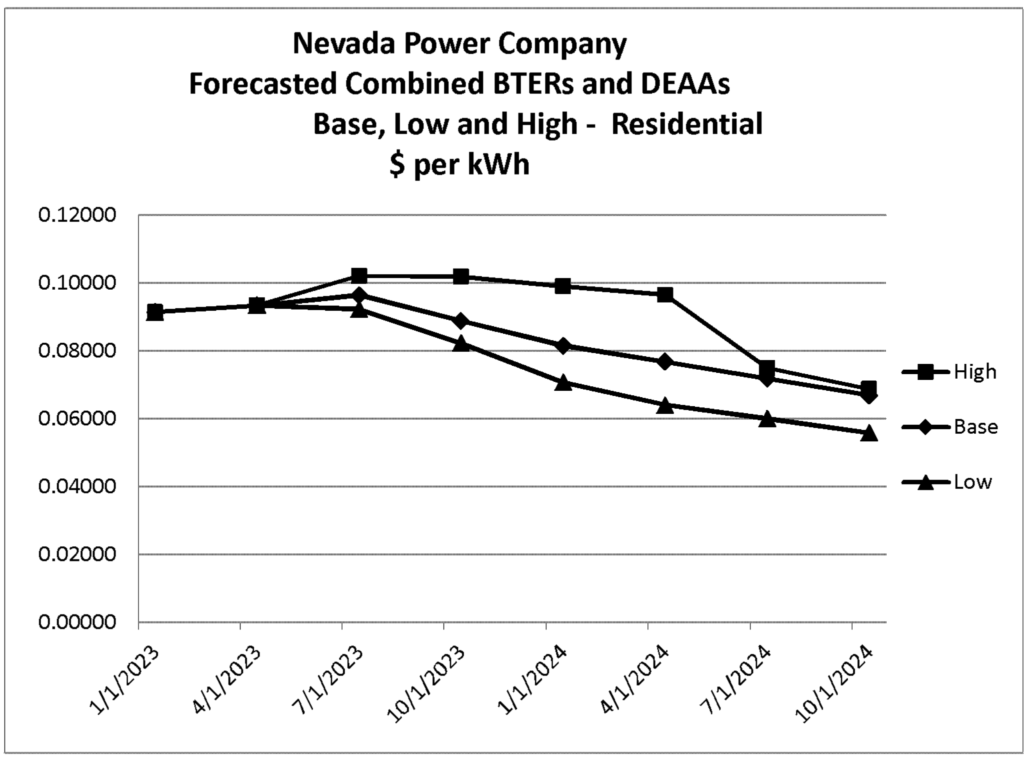

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Figure Naughton-Direct-2

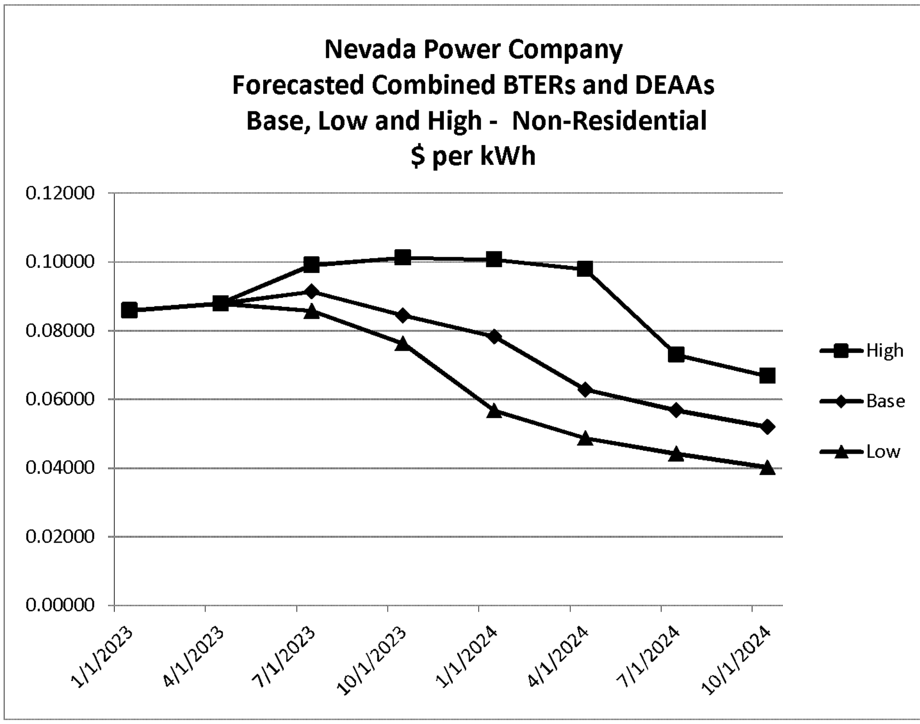
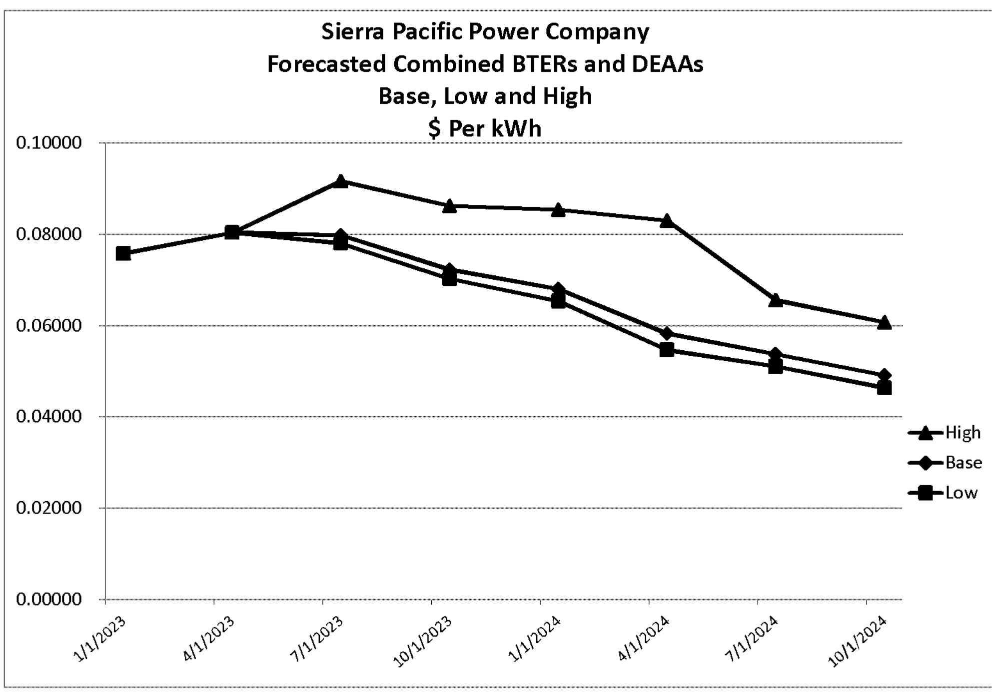


Figure Naughton-Direct-3 shows the combined 2023-2024 forecasted Sierra BTERs and DEAAs for the plan.

Figure Naughton-Direct-3



8. 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.

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

A. Yes

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

STATEMENT OF QUALIFICATIONS

Jenny Naughton
Revenue Requirement & FERC Manager
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-4222

Mrs. Naughton has been an employee of NV Energy since 2017, where she has spent time in the Major Accounts and Regulatory Pricing & Economic Analysis departments, recently transitioning to the role of Revenue Requirement & FERC Manager within the Revenue Requirement & Regulatory Accounting group. Her current responsibilities are focused upon monthly, quarterly, and annual fuel and purchased power and deferred energy recovery mechanisms and their corresponding rate development and required filings, along with the preparation of regulatory earned rate of return and revenue requirement calculations.

Prior to joining the Company, Mrs. Naughton worked in various finance & accounting functions across different industries and was most recently employed by KP Aviation, an aftermarket aviation component retailer, as the Controller.

Professional Experience

NV Energy, Reno, NV
Revenue Requirement & FERC Manager, Revenue Requirement & Regulatory Accounting
March 2022 to Present

- 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

Pricing Specialist, Regulatory Pricing & Economic Analysis
April 2021 to March 2022

- Conducted research and provided analytical support and guidance for internal and external customers
- Coordinated with several departments to gather data and perform the customer weighting factor study
- Prepared analysis and support for alternative rate options for inquiries by large customers

Major Accounts Specialist, Major Accounts
Senior Major Accounts Analyst, Major Accounts
November 2017 to April 2021

- Performed analysis of rates, market and growth trends, energy demand and usage, budgeting, billing, load profiling, and usage/cost drivers for substantial energy use customers
- Provided analysis and presentations used in the Company's large customer retention efforts
- Developed and performed initial monthly calculations of Market Price Energy and other rates
- Managed and prepared large customer contracts for standby service and gas transportation

KP Aviation, Reno, NV
Controller, Finance & Accounting
Operations Analyst, Finance & Accounting
January 2016 to November 2017

- Responsible for the preparation of the Company's financial reporting and statements
- Prepared and monitored project budgets, projections, and performance reporting
- Designed and managed the migration and implementation of new finance & accounting software

Ruby Seven Studios, Reno, NV
Finance Manager
August 2015 to December 2015

- Managed all day-to-day business operations of the company, including all accounting functions, human resources, payroll, and compliance

Klondex Mining, Reno, NV
Staff Accountant
May 2015 to August 2015

- Preparing journal entries, account reconciliations, and supporting schedules for the corporate ledger and other business units
- Maintained the daily log for ore production and prepared monthly accrual entries accordingly

Sutton Place Limited, Reno, NV
Staff Accountant
March 2013 to May 2015

- Prepared and presented quarterly and annual projections, budgets, financial statements, reconciliations, and adjusting journal entries with all supporting schedules and documentation for various clients, including the company, for a high-net worth family office
- Performed weekly cash flow statements and managed all cash transactions, accounts payable, accounts receivable, and payroll for all applicable clients

West Coast Contractors of Nevada, Inc., Reno, NV
Staff Accountant
April 2012 to March 2013

- Provided support for Operations by including job set-up, cost management, producing and analyzing projects projections and forecasts.
- Managed all project's accounts payable & receivable
- Prepared monthly adjusting journal entries, reconciliations, and quarterly and annual financial statements, with all supporting schedules and documentation

Caesars Entertainment, Las Vegas, NV
Operations Accountant, Accounts Receivable
May 2011 to March 2012

- Managed and maintained 20 hotel wholesale accounts and various other City Ledger accounts for 26 properties nationwide by applying all daily payments received, performing all necessary adjustments, and submitting all invoices on a weekly basis

Education

University of Nevada, Reno
Bachelor of Science in Finance, Emphasis in Accounting, May 2011

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JENNY NAUGHTON, 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: September 1, 2022

Jenny Naughton
JENNY NAUGHTON

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

2022 Energy Supply Plan
Docket No. 22-09___

Prepared Direct Testimony of

Timothy Pollard

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

A. My name is Tim Pollard. My current position is Director for Load Forecasting, Research and Analytics in the Rates and Regulatory Affairs department for Nevada Power 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, Nevada. I am filing testimony on behalf of the Companies.

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

A. I previously worked in the Rates and Regulatory Affairs department for 15 years as a Technical Lead within the department where my main focus was on regulatory cost of service and rate design issues. In my current position, my primary focus is on Load Forecasting and Load Research issues for the Companies.

I have been an expert witness before the Public Utilities Commission of Nevada ("Commission") regarding load forecasts, cost of service and regulatory pricing issues in support of the Rate & Regulatory Affairs department's responsibilities. I was also previously employed by the Companies in 2004 as a Load Forecasting Economist within the Resource Planning department. My educational background, previous positions and professional experience are summarized in **Exhibit Pollard-Direct-1**.

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

A. As a Director within this group, my responsibilities include leading and overseeing the Companies' load forecasts and historical load research activities for the Companies. This includes all technical aspects of their historical and forecast class load data used for filings with the Commission.

4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY WITH THE COMMISSION?

A. Yes. Most recently, I provided testimony with the Commission in the Sierra's General Rate Case proceeding Docket No. 22-06014. A full list of cases in which I have provided testimony before the Commission can be found in **Exhibit Pollard-Direct-1**.

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

A. I sponsor the Companies' proposed updates to the short-term load forecast approved by the Commission in the 2021 Joint Triennial IRP (the "2021 IRP Forecast"), and the corresponding Technical Appendices, to support the 2022

Joint Energy Supply Plan Update ("ESP") for the 2023-2024 action plan period. Because this material is identical for both the ESP and the Third IRP amendment to the IRP, these materials are physically located in the Technical Appendices accompanying the load forecast narrative for the IRP. These include:

- IRP LF-1 2021 Load Forecast Technical Appendix;
- IRP LF-2 State Demographer 2021 Long-Term Population Projections;
- IRP LF-3 State Demographer 2021 Governor Certified Series – Population Estimates of Nevada's Counties;
- IRP LF-4 Las Vegas Convention and Visitors Authority ("LVCVA") Year-to-Date executive summary for 2021;
- IRP LF-5 2021 CBER Clark County Population Forecast June 2021; and
- IRP LF-6 S&P Global IHS Markit population and economics forecast.

6. Q. ARE YOU FILING WORKPAPERS WITH THIS ESP FORECAST?

A. Yes, a comprehensive set of load forecasting files will be supplied on electronic media for this filing.

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

A. Yes. Technical Appendix IRP LF-6 contains confidential copyrighted and proprietary data from S&P Global IHS Markit Insights. The Companies receive that data under a paid subscription.

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

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

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

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

10. Q. PLEASE SUMMARIZE THE COMPANIES' PROPOSED UPDATES TO THE APPROVED 2021 JOINT IRP FORECAST.

A. The 2021 IRPA Third Forecast provides the foundation for all other load forecasts included in this Third Amendment filing. The Companies request approval of the following updates regarding this updated 2021 IRPA Third Forecast and ESP Forecast:

- Includes in the 2021 IRPA Third Forecast an updated economic outlook issued in December 2021,
- Increases to estimated adoption rates of electric vehicles ("EV") are incorporated into the updates following the further development of information as part of the Economic Recovery Transportation Electrification Plan ("ERTEP") approved by the Commission in Docket No. 21-09004,

- Updates to Energy Efficiency ("EE") and Demand Response ("DR") programs through April 2022,
- Slightly higher reductions to system demand and energy requirements on account of increased forecast for solar photovoltaic ("solar PV") net-energy metered ("NEM") private generation installations, and
- Expected changes in large customer business activity, which are discussed below.

11. Q. WHAT IS THE IMPACT OF THESE UPDATES FROM THE PREVIOUSLY APPROVED FORECAST?

A. Table Pollard-Direct-1 below summarizes the change in forecast annual energy gigawatt-hour ("GWh") sales and peak megawatts ("MW") over the 2022-2041 period, including the ESP Update period of 2023-2024, for the updated forecast. The table shows that the annual energy sales increase in 2023 by 592 GWH, or 1.9 percent, and in 2024 by 688 GWh, or 2.1 percent, from the approved forecast. The updated peak MW values increase by 95 MW in 2023, or 1.2 percent, and 185 MW in 2024, or 1.1 percent, from the 2021 Joint IRP value.

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

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

	Energy (GWh)			Peak (MW)		
		2021			2021	
Year	Current	Joint IRP	Difference	Current	Joint IRP	Difference
2022	32,047	31,070	977	7,829	7,715	114
2023	32,411	31,819	592	7,938	7,843	95
2024	33,223	32,536	688	8,132	7,947	185
2025	33,903	32,859	1,044	8,217	7,999	218
2026	33,863	32,602	1,261	8,267	7,994	273
2027	34,362	33,104	1,258	8,293	8,106	187
2028	34,927	33,523	1,404	8,522	8,217	305
2029	35,407	33,815	1,592	8,608	8,225	383
2030	35,675	33,958	1,717	8,777	8,287	490
2031	35,929	34,117	1,812	8,770	8,350	420
2032	36,212	34,326	1,885	8,825	8,398	427
2033	36,452	34,477	1,975	8,894	8,457	437
2034	36,742	34,649	2,093	9,015	8,535	480
2035	37,160	34,830	2,330	9,061	8,518	543
2036	37,579	35,058	2,521	9,180	8,598	582
2037	37,830	35,207	2,623	9,281	8,648	633
2038	38,110	35,387	2,723	9,243	8,689	554
2039	38,395	35,567	2,828	9,377	8,764	613
2040	38,711	35,773	2,939	9,478	8,771	707
2041	38,954	35,906	3,048	9,679	8,852	827
Compound Annual Growth Rate (CAGR)						
22-32	1.2%	1.0%	---	1.2%	0.9%	---
32-41	0.7%	0.5%	---	0.9%	0.5%	---

12. Q. BRIEFLY SUMMARIZE THE UPDATES MADE FOR THE DECEMBER 2021 ECONOMIC OUTLOOK.

A. The 2021 IRPA 3rd Forecast uses an extrapolation of population series using the average of the annual growth rates obtained from the State Demographer's 20-year population projections (2021-2040) by county, the State Demographer's 2021 Governor Certified Series population estimates 2001 to 2021, the LVCVA year-to-date executive summary of key tourism indicators, the University of Nevada, Las Vegas's Center for Business and Economic

Research's ("CBER") long-term population forecast (released June 2021) for Clark County, and the S&P Global's IHS Markit population and economics forecast (released December 2021), with minor adjustments to smooth forecasted growth. See the IRP LF-1 Technical Appendix for further details on after-the-model sales adjustments and development of the economic data provided in the IRP LF-2 through IRP LF-6 Appendices.

13. Q. HOW HAS THE FORECAST BEEN UPDATED FOR CHANGES IN FORECASTED ELECTRIC VEHICLE GROWTH?

A. This Third 2021 IRP Forecast provides changes to the forecasted growth of EVs in Nevada. The change incorporated into this amendment assumes that EVs, as a percentage of new vehicles sold in Nevada, will increase to 52.9 percent by 2032 and increase at 0.1 percent per year thereafter. This compares to the projection in the 2021 Joint IRP that sales of such vehicles would constitute only 11.2 percent of all new vehicle sales by 2030 and increase by 0.1 percent thereafter. This significant change is driven by the increasing speed at which EVs are considered as customers' next vehicle purchase.[1]

In comparison to the 2021 Joint IRP, the updated statewide EV energy sales are estimated to increase 203 GWh by 2032 (combined for both Companies). Further detail is provided in the IRP LF-1 Technical Appendix, but Table Pollard Direct-2 below details the change to the forecast from this input.

[1] See https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/cleanenergy/ertep/BEV-Adoption-Forecast.pdf.

TABLE POLLARD DIRECT-2
ELECTRIC VEHICLE CUMULATIVE GWH CHANGES

	Current			2021 Joint IRP			Change		
Year	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total
2022	72	24	96	12	4	16	60	20	80
2023	105	35	140	24	8	32	81	27	109
2024	138	46	184	39	13	52	99	33	132
2025	172	57	229	58	19	78	113	38	151
2026	207	69	276	81	27	108	126	42	168
2027	241	80	322	107	36	143	134	45	178
2028	276	92	367	137	46	183	138	46	184
2029	311	104	415	171	57	227	140	47	187
2030	347	116	463	204	68	272	143	48	191
2031	385	128	513	238	79	317	147	49	196
2032	424	141	566	272	91	363	152	51	203
2033	463	154	618	307	102	410	156	52	208
2034	502	167	670	343	114	457	159	53	213
2035	541	180	721	378	126	505	162	54	217
2036	579	193	772	414	138	552	165	55	220
2037	617	206	822	450	150	601	166	55	222
2038	654	218	872	487	162	649	167	56	223
2039	691	230	922	524	175	698	168	56	224
2040	728	243	971	561	187	748	167	56	223
2041	765	255	1,020	598	199	798	166	55	222

14. Q. WHAT UPDATES ARE INCLUDED IN THE 2021 IRPA THIRD FORECAST FOR CHANGES TO THE FORECAST FROM DEMAND-SIDE MANAGEMENT ("DSM") PROGRAMS?

A. This 2021 IRPA Third Forecast accounts for updates to the DSM programs, as of April 2022, that were provided by the Energy Efficiency and Conservation groups. The updates result in lower growth in energy use reductions for the residential customer group and higher growth in energy use reductions in the commercial customer group starting in 2024. This results in larger reductions in earlier years of the forecast, but which decrease over time and lead to higher forecast energy sales in the later years of the forecast period. Further detail is provided in the IRP LF-1 Technical Appendix, but Table Pollard Direct-3 below details the change to the forecast from these changes.

TABLE POLLARD DIRECT-3
ENERGY EFFICIENCY SALES REDUCTION (GWH) CHANGES

	Current			2021 Joint IRP			Change		
Year	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total
2022	340	157	498	380	187	568	(40)	(30)	(70)
2023	540	252	792	574	278	852	(34)	(26)	(60)
2024	741	349	1,091	769	372	1,141	(28)	(22)	(50)
2025	944	450	1,394	963	467	1,430	(19)	(17)	(36)
2026	1,147	552	1,700	1,157	564	1,720	(9)	(11)	(21)
2027	1,351	657	2,008	1,351	662	2,014	(0)	(5)	(5)
2028	1,556	765	2,321	1,547	763	2,309	9	3	12
2029	1,762	875	2,637	1,742	864	2,606	20	11	31
2030	1,968	985	2,953	1,936	966	2,902	31	19	50
2031	2,174	1,096	3,269	2,131	1,067	3,198	42	28	71
2032	2,380	1,207	3,587	2,327	1,168	3,495	53	38	92
2033	2,587	1,318	3,905	2,522	1,270	3,792	65	48	113
2034	2,794	1,430	4,224	2,718	1,371	4,089	76	59	135
2035	3,002	1,542	4,544	2,915	1,471	4,386	87	71	158
2036	3,211	1,654	4,866	3,112	1,572	4,684	99	82	182
2037	3,421	1,767	5,188	3,309	1,673	4,982	112	94	206
2038	3,631	1,880	5,512	3,507	1,774	5,281	124	107	231
2039	3,842	1,994	5,836	3,705	1,874	5,580	137	120	257
2040	4,055	2,108	6,162	3,904	1,975	5,879	150	133	283
2041	4,268	2,222	6,489	4,104	2,076	6,179	164	146	310

15. Q. HOW DO THE DR IMPACTS CHANGE THE COMPANIES' PEAK LOADS IN THIS 2021 IRPA THIRD FORECAST?

A. Updates to the DR impacts for both Nevada Power and Sierra are included in this 2021 IRPA Third Forecast. The forecasted estimates, provided by the Energy Efficiency and Conservation groups, result in slightly higher peak reductions (lower peaks) for both Nevada Power and Sierra in the earlier years of the forecast, while the impact to later years is slightly lower (higher peaks), which are driven by lower program growth initially from those estimated in the 2021 Joint IRP. Further detail is provided in Technical Appendix LF-1, but Table Pollard Direct-4 below details the change to the forecast from these changes.

TABLE POLLARD DIRECT-4
DEMAND RESPONSE AVOIDED CAPACITY (MW) CHANGES

	Current			2021 Joint IRP			Change		
Year	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total
2022	127	21	148	137	26	163	(10)	(5)	(15)
2023	130	23	154	134	30	164	(4)	(7)	(10)
2024	132	28	160	134	34	169	(2)	(6)	(8)
2025	141	34	175	129	37	167	12	(4)	8
2026	146	35	181	138	39	177	8	(5)	4
2027	156	35	191	149	40	189	7	(4)	2
2028	155	42	196	151	43	194	3	(1)	2
2029	165	42	208	154	43	197	11	(1)	11
2030	166	46	212	145	46	191	22	(0)	21
2031	170	48	218	152	47	200	17	1	18
2032	176	50	225	160	46	206	16	3	19
2033	176	50	226	169	48	216	8	2	9
2034	178	51	229	178	49	227	1	1	2
2035	185	51	236	188	50	238	(3)	1	(2)
2036	190	49	239	187	51	238	3	(2)	1
2037	188	56	245	196	52	248	(7)	4	(3)
2038	195	56	252	160	53	213	36	3	39
2039	194	58	252	159	54	213	36	4	39
2040	202	60	262	158	54	212	44	6	50
2041	203	58	260	160	54	214	43	3	46

16. Q. WHAT CHANGES HAVE BEEN MADE TO CUSTOMER SOLAR PV INSTALLATIONS FOR THIS FORECAST UPDATE?

A. Larger additions of customer NEM solar PV installations have been incorporated into this amendment update. The result is a decrease in solar reduction in Nevada Power's territory, and an increase in solar reduction starting in 2028 in Sierra's territory. Further detail is provided in the IRP LF-1 Technical Appendix, but Table Pollard Direct-5 below details the change to the forecast from these changes.

TABLE POLLARD DIRECT-5
ANNUAL SALES (GWH) REDUCTIONS FROM NEM INSTALLATIONS

	Current			2021 Joint IRP			Change		
Year	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total	Nevada Power	Sierra	Total
2022	55	4	59	53	3	56	2	1	3
2023	150	11	162	145	9	154	6	2	8
2024	243	19	261	234	15	248	9	4	13
2025	332	26	357	319	20	340	12	5	18
2026	418	32	450	402	26	428	16	7	23
2027	501	39	540	481	31	512	19	8	27
2028	578	46	624	556	36	592	22	10	32
2029	649	52	701	623	41	664	26	11	36
2030	712	58	770	683	46	729	29	12	41
2031	771	63	835	740	50	790	32	13	45
2032	831	69	900	796	55	851	35	14	49
2033	890	75	965	852	60	912	38	15	53
2034	949	81	1,030	908	64	972	41	16	57
2035	1,008	86	1,094	964	69	1,033	44	17	61
2036	1,067	92	1,159	1,021	74	1,094	47	18	65
2037	1,127	98	1,224	1,077	78	1,155	50	19	69
2038	1,186	103	1,289	1,133	83	1,216	53	20	73
2039	1,245	109	1,354	1,189	88	1,277	56	21	78
2040	1,304	115	1,419	1,245	92	1,337	59	22	82
2041	1,364	120	1,484	1,301	97	1,398	62	24	86

17. Q. WHAT UPDATES WERE MADE FOR FORECAST LARGE CUSTOMER ACTIVITY IN THIS AMENDMENT?

A. One large casino is being added to the Nevada Power forecast, and another casino's operations are being moved up one year (2023 from 2022), which are increasing loads by 183 GWh in 2024 and increasing to 201 GWh by 2030. There was also a small change to one Sierra large mining customer that reduces the sales forecast by 35 GWh annually beginning in 2022.

18. Q. HAVE THE COMPANIES MADE ANY CHANGES TO THEIR FORECAST METHODOLOGY SINCE THE COMPANIES' 2021 JOINT IRP FILING FORECAST WAS APPROVED BY THE COMMISSION?

A. Yes. In this 2022 ESP Forecast, Google mobility data was not used to adjust for COVID-19 impacts due to Nevada's population largely returning to the office after the 2020 pandemic. The impact of removing this variable in the average kilowatt-hour per customer modelling for residential and small commercial customer groups is small, less than one percent of the overall model specification usage. But, the ultimate impact on forecasted average per customer usage is even less as the 2020-2021 data is now embedded in the overall model as more of a temporary variation over the data used in the models.

19. Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS REGARDING THE 2022 ESP FORECAST.

A. The Companies request the following regarding the 2022 ESP Forecast:

- A finding, consistent with NAC § 704.9321, that the 2022 ESP Forecast is based on substantially accurate data, adequately demonstrated and defended, and adequately documented and justified;
- A finding that the 2022 ESP Forecast, as described in the ESP Narrative, the Technical Appendices, and my testimony, contains all of the items required by NAC § 704.925 and other applicable regulations; and
- A finding that the 2022 ESP Forecast is suitable for making short-term planning decisions.

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

A. Yes, it does.

TIM POLLARD
DIRECTOR, LOAD FORECASTING, RESEARCH & ANALYTICS
RATES & REGULATORY AFFAIRS
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-4006

Mr. Pollard has been an employee of NV Energy for fifteen years and is currently the Director of Load Forecasting and Load Research. His responsibilities are focused upon leading the load research and forecasting teams for regulatory filings and special assignments in support of the Rate & Regulatory Affairs 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-NVEnergy 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, and 22-06014.
CPUC Applications: 08-08-004.

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: September 1, 2022

TIMOTHY POLLARD

SHANE PRITCHARD

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2022 Energy Supply Plan
Docket No. 22-09___

Prepared Direct Testimony of

Shane Pritchard

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

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

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

A. I hold a Bachelor of Science Degree in Mechanical Engineering from the University of Buffalo in Buffalo, New York. I served in the U.S. Navy between 1991 and 1996. Before joining the Companies, I worked for Titanium Metals Corporation and then for Alstom Power. In my current role, I serve as Director of Renewable Energy and Origination. My responsibilities include the procurement and contract negotiations for renewable and non-renewable energy resources. More details regarding my professional background and experience are set forth in **Exhibit Pritchard-Direct-1**.

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

A. Yes. Most recently I provided written testimony in Docket No. 21-06001, the 2021 Joint Integrated Resource Plan ("IRP") and Docket No. 22-03024, the Companies' First Amendment to the 2021 Joint IRP.

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

A. I sponsor the Section 2.D. of the 2022 Joint Energy Supply Plan Update ("ESP") as it relates to renewable energy planning for the 2023-2024 action plan period. I also sponsor Section 9.B of the ESP which provides an update on the progress of the White Pine Pumped Storage Hydro ("PSH") project.

5. Q. PLEASE DESCRIBE NEVADA'S RENEWABLE PORTFOLIO STANDARD ("RPS").

A. Nevada utilizes a portfolio energy credit ("PC") system to measure Renewable Portfolio Standards ("RPS") compliance. Eligible PCs can come from multiple sources beyond just net current year renewable generation. The most common source of PCs from non-current year net renewable generation are banked PCs rolled forward from prior compliance years, eligible station usage PCs, grandfathered solar multiple PCs, and finally PCs derived from energy efficiency and demand response programs.

Nevada's RPS requirement for calendar year 2022 is set at 29 percent of retail sales. This means that Nevada Power and Sierra provide renewable energy credits equal to 29 percent of their retail sales. The RPS will increase to 34 percent in 2024, 42 percent in 2027, and 50 percent in 2030 and each calendar year thereafter.[1] The revised RPS requirements also established an aspirational goal to have one hundred percent of the energy generated to meet Nevada customer load come from carbon-fee resources by 2050.[2]

6. Q. PLEASE DESCRIBE THE RPS RENEWABLE PLAN DEVELOPED FOR THE ESP UPDATE.

A. The Companies use an Excel model which takes into account all credit sources and obligations to determine whether the Companies will have a sufficient number of PCs to meet their RPS obligations. If, outside the ESP action period, the model indicates that the PC supply is insufficient to meet the RPS, generic placeholder projects are added, as needed, to fill the credit gaps. Key inputs to the model include a list of current operating renewable resources, all approved renewable resources under development or construction, and all other sources of eligible credits. The model incorporates all statutory and regulatory limitations, as well as non-RPS portfolio credit obligations, in order to calculate the total number of eligible credits available to meet the RPS for each planning year. This total is then compared against the forecast credit requirement to determine whether each company will have a sufficient number of credits to meet its RPS obligation. Below are the key assumptions that are incorporated into the model.

- Existing power purchase agreements ("PPAs") expire in accordance with the contract terms and are not automatically renewed;[3]

[1] SB358 § 22, codified as NRS 704.7821
[2] *Id.* at § 8(2), codified as NRS 704.7820
[3] This does not imply that the Companies would rule out renewing existing agreements. Rather, it recognizes the uncertainty as to whether the resource could continue to support ongoing generation, and whether the Companies and the counterparty can come to terms on renewing the agreement.

- The Companies adjusted the expected amount of energy and PCs from renewable facilities for the period of 2022-2025 in cases where the historic generation, based on two or more years of data, consistently varied from that of the contractual or expected supply table. This is consistent with the methodology that the Companies have used in past when developing IRP, IRP amendment and ESP compliance outlooks. This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-term plans;
- The projected number of PCs derived from the Renewable Generations incentive programs plateaued in 2020 with the last of the incentivized solar systems now installed. Starting in 2021, the expected number of credits 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;
- Per NAC 704.8927, solar facilities placed in service before December 31, 2015, qualify for the solar multiplier; facilities placed in service after do not qualify;
- The plan assumes that the percent of annual PC requirements met from demand side management (“DSM”) measures is limited to no more than 10 percent of the credit total for 2022 through 2024 before dropping to zero effective 2025. The plan also assumes, based on current DSM kPC projections, that Sierra may not have enough DSM PCs to completely fill the 10 percent cap in 2024;
- Surplus PCs are carried forward without limitation, and the plan assumes no surplus PC sales;

- The plan assumes that generation from both company-owned solar photovoltaic ("PV") systems and PPA projects would be degraded starting the year following the first full year of operation. Geothermal generation which utilizes geothermal brine in the generating process would continue to qualify for station usage credits, all other technologies would no longer qualify;
- The plan accounts for all Commission approved and existing NV GreenEnergy Rider ("NGR") and Energy Supply Agreements ("ESAs") as of July 31, 2022, where PCs associated with all or a portion of the output from a renewable facility(s) has been assigned to a customer under the NGR, the Market Price Energy or Large Customer Market Price Energy tariffs, and therefore cannot be used by the Companies in meeting their RPS credit requirements;
- 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 plan includes Iron Point 250 MW PV with battery energy storage system ("BESS") and Hot Pot Solar 350 MW PV with BESS, with the energy and PCs split 56 percent Nevada Power and 44 percent Sierra;

- The plan includes the North Valley geothermal ("North Valley Geothermal" or "North Valley") PPA approved in Docket Number 22-03024. North Valley Geothermal is a 25 MW geothermal plant with an estimated commercial operation date of December 31, 2022. Sierra will be the sole off taker of the energy and PCs. The total number of PCs from this project includes station usage PCs. Certain geothermal station usage, the energy for the extraction and transportation of geothermal brine or used to pump or compress geothermal brine, is eligible for certification under the NRS 704.78215(3)(b). Station usage PCs for this facility were estimated at 15 percent of net;
- The annual amount of energy produced by solar PV systems paired with BESS has been reduced to account for battery loses. The adjustment recognized that not all of the energy produced by PV arrays paired with energy storage will be delivered real-time to the grid. Some of the energy will be stored and dispatched at a later time when needed. The process of charging and discharging the batteries will result in energy loses; and
- An adjustment has been added to the model to capture the generation and PCs lost due to curtailment. 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 forecasted amount of energy curtailed over the 2023/2024 action period for Nevada Power and Sierra is minimal: Nevada Power averaged .25 percent over the two-year action period, Sierra averaged .04 percent over the two-year action period.

7. Q. PLEASE EXPLAIN THE ASSUMPTIONS AND METHODOLOGY UNDERLYING THE MODIFIED SHORT-TERM RENEWABLE EXPANSION PLAN.

A. The modified renewable expansion plan developed for short-term planning purposes captures actual historical generation trends based on two or more years of operating data. The Companies adjusted the supply table based on this historical trend to reflect the most recent operating data after coordinating with internal contract managers to account for potential short-term anomalies. Historical output trends for Sierra contracted renewable projects resulted in an adjustment to seven projects, all decreases. In total, these adjustments lowered the amount of renewable energy by an average of 2.1 percent for the 2023-2024 ESP action period.

The same approach for Nevada Power resulted in adjustments to the amount of renewable energy for seven projects, six decreases and one increase. In total, these adjustments lowered the amount of renewable and derived credits by an average 1.5 percent for the 2023-2024 ESP action period. The Companies believe that this approach maximizes the reliability and accuracy for the overall energy supply used in short-term planning.

8. Q. PLEASE DESCRIBE NEVADA POWER'S ESP RPS OUTLOOK AND ANY POTENTIAL CONCERNS.

A. Nevada Power exceeded the 2021 RPS requirement of 22 percent ending 2021 with an overall RPS compliance result of 30.1 percent. Nevada Power is currently positioned to meet its 2022-2024 RPS obligations. Short of a catastrophe impacting multiple operating renewable facilities, the forecasting model currently indicates that Nevada Power should have no issues in fully complying with the RPS in 2023 and 2024. A number of the renewable resources that are currently under development are facing delays, shortfalls, and/or cancellations due to the various market conditions surrounding the solar photovoltaic ("PV") and Battery Energy Storage System ("BESS") markets. While no project in the pipeline has formally notified the Companies that it will not go forward, in the past year several project developers have communicated difficulties obtaining major equipment at costs enabling them to fulfill their contracted obligations. The Companies will continue to monitor this situation.

9. Q. PLEASE DESCRIBE SIERRA'S RPS OUTLOOK AND ANY POTENTIAL CONCERNS.

A. Sierra exceeded the 2021 RPS requirement of 22 percent ending 2020 with an overall RPS compliance result of 31.9 percent. Like Nevada Power, barring any unforeseen catastrophes, Sierra is also currently positioned to meet its 2022-2024 RPS obligations. Sierra does not enjoy the same level of cushion, so the post 2024 impact of potential lost generation and credits resulting from project delays and/or cancelations described above, would impact Sierra sooner and the magnitude of that impact would be more severe.

10. Q. PLEASE DESCRIBE PROGRESS ON THE WHITE PINE PUMPED STORAGE HYDRO PROGRESS.

A. In Docket No. 22-03024 the Commission approved the Companies' request to spend $3.5 million to continue due diligence on and support the development of the White Pine PSH project. Per Directive number 5 of the order, the Companies were required to provide a status update on the project. The Companies continue to monitor the development of the White Pine Pumped

Storage Hydro PSH project and to finalize negotiations for the Development Services Agreement with rPlus Energies. More detail is provided in the narrative part 9.B.

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

A. Yes

SHANE E. PRITCHARD
6226 West Sahara Ave.
Las Vegas, NV 89151-001
702-439-3545
shane.pritchard@nvenergy.com

EDUCATION: BS - Mechanical Engineering - University of Buffalo – 1991

NV Energy:

2018 – Present: Director, Renewable Energy and Origination

Responsible for the evaluation of strategic renewable opportunities that increase shareholder and customer value. Directs contract negotiations and oversees the delivery of the supply side Action Plan outlined in the Integrated Resource Plan for origination-related activities. Ensures alignment with short and long-term organizational goals and objectives. Works closely with top executive management to keep them apprised of strategic opportunities and challenges.

2015 – 2018: Senior Project Manager for Renewable Energy and Origination

Responsible for developing customer proposals for green power and customer choice programs and due diligence assessment of potential generating asset purchases. Supported bid and regulatory processes for contracting new renewable assets and develops testimony and responds to data requests in support of regulatory filings. Project manager and customer-facing representative for new commercial businesses interfacing with generating stations. Developed generation projects and strategies to solve transmission and distribution problems.

2014 – 2015: Operations Manager for Silverhawk Station

Led a team in the operation of a 600 MW combined cycle power plant. Responsible for personnel safety, plant performance, operations budget, NERC/WECC compliance, environmental compliance and compliance with applicable OSHA and other safety regulations. Planned and facilitated personnel training and led several continuous improvement efforts including implementation of Human Performance Improvement methods and enhanced event reporting.

2012 – 2014: Maintenance Manager for Arrow Canyon Complex
2009 – 2012: Operations & Maintenance Manager for Silverhawk Station
2008 – 2009: Engineering Manager for Arrow Canyon Complex
2007 – 2008: Maintenance Manager for Chuck Lenzie Station
2005 – 2007: Plant Engineer for Chuck Lenzie Station

Other experience:

2000 – 2005: Alstom Power - Field Service Engineer

- Plant inspections, emissions tuning, technical consultant and project leader for plant retrofits
- Business development and customer relations

1997 – 2000: Titanium Metals Corporation (Timet) - Project Engineer

- Implemented capital projects from design through commissioning in support of plant operations

US Navy:

1991 – 1996: US Navy Nuclear Power

Test Director: USS Abraham Lincoln dry-dock overhaul

- Planned, scheduled and executed complex nuclear reactor plant tests

- Managed shipyard and Navy efforts to repair and upgrade reactor plant systems
- Assisted civilian electrical engineers in E&IC system troubleshooting

Reactor Electrical Division Officer: USS Abraham Lincoln at sea
- Led and trained 30 electricians to operate and maintain propulsion plant electrical systems
- Operated nuclear power plants and maintained associated reactor electrical systems
- Aircraft carrier operations Officer of the Deck

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

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, SHANE PRITCHARD, 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: September 1, 2022

SHANE PRITCHARD

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

2022 Energy Supply Plan
Docket No. 22-09___

Prepared Direct Testimony of

Vincent Vitiello

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

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

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

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

Prior to joining the Companies, I was employed for six years by Chevron Corporation ("Chevron") as the Assistant Executive Director at Nevada Cogeneration Associates #1 and Nevada Cogeneration Associates #2. Prior to that, I worked at Southwest Gas Corporation ("SWG") for 14 years, in the major accounts and engineering 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 Company's natural gas transportation and storage assets necessary to ensure the adequate supply of natural gas to the Company's 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 ("FERC") 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 in Docket Nos. 22-0516, 22-05017, and 22-05016.

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

A. In my testimony, I sponsor the following sections in the Companies' Energy Supply Plan ("ESP").

- Section 5.B ("Gas Transportation Plan")

6. Q. PLEASE SUMMARIZE THE COMPANIES' NATURAL GAS TRANSPORTATION STRATEGY.

A. Section 5.B of the ESP summarizes the Companies' gas transportation strategies. The Companies are not proposing to add to their existing gas transport portfolio.

Sierra is seeking approval to maintain its current natural gas transportation portfolio by renewing natural gas transportation contracts with evergreen rights that expire in 2023. The request to approve the renewal of contracts with evergreen rights that expire in 2023 enables Sierra to provide the pipelines with the required notice to renew them.

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

7. Q. ARE THERE ANY INTERSTATE PIPELINE RATE CASES THE COMPANIES ARE PARTICIPATING IN?

A. Yes. In last year's Gas Information Report ("GIR") and ESP update, it was reported that Sierra was in pre-hearing settlement discussions with TC Energy – Gas Transmission Northwest ("GTN") regarding their requirement to file of a rate with the Federal Energy Regulatory Commission (FERC) by June 1, 2021, and that a settlement was not reached. However, a few days prior to Sierra's required June 1, 2021, filing date for the GIR and ESP filings, GTN and its shippers agreed to extend the negotiations. On September 29, 2021, GTN and its shippers agreed to a settlement which kept GTN's rates the same, with a moratorium for no rate increases through December 31, 2023.

Sierra has been participating in pre-hearing settlement discussions since September 2021 with Northwest Pipeline ("NWPL") and its shippers. NWPL was required to file a rate case with the FERC by July 1, 2022. On June 29, 2022, NWPL reached a settlement in principle with its shippers. To provide more time to memorialize the settlement in principle, an unopposed petition to extend the rate case filing date was submitted to FERC. The petition was granted, extending the filing requirement from July 1, 2022, to August 31, 2022. At this time, NWPL plans on filing this settlement at the FERC by August 31 which will lower rates. A three-year rate moratorium has been established, and a five-year comeback provision.

The Tuscarora Gas Transmission Pipeline ("Tuscarora") was required by the FERC to file a rate case no later than July 31, 2022. Tuscarora held pre-hearing settlement discussions beginning in April 2022 which Sierra participated in. A settlement was not reached during these discussions and therefore Tuscarora filed its rate case on

July 29, 2022. Sierra will participate in this rate case and monitor this proceeding closely.

8. Q. DID THE COMPANIES EVALUATE THE ADEQUACY OF THE CURRENT FIRM INTERSTATE GAS TRANSPORTATION CONTRACTS TO ENSURE SUFFICIENT NATURAL GAS SUPPLY TO THE COMPANIES' GENERATION FLEET, ALONG WITH SIERRA'S NATURAL GAS LOCAL DISTRIBUTION COMPANY ("LDC")?

A. Yes, the production cost model PROMOD was used to further evaluate the system reliability and projected firm gas transportation needs for northern and southern generation plants, and Sierra's LDC. The One Nevada Transmission Line ("ON Line") was assumed to be in service for these analyses. A summary of the results is set forth below.

Nevada Power: For Nevada Power, a load forecast with a hot summer and a cold winter (based on 1 in 10 peak cooling-degree-day and heating-degree-day) was created and PROMOD was used to further evaluate projected firm gas transportation needs. Additional details on the development of the hot summer/cold winter load forecast are provided in Technical Appendix LF-1, Section VI. The following two scenarios were evaluated: 1) normal weather conditions with existing firm gas transportation contracts; and 2) hot summer/cold winter weather conditions with existing firm gas transportation contracts. 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 are 22 days for 2023 and 33 days for 2024. Under extreme weather the projected number of days are 13 for 2023 and 25 for 2024. Historically, Nevada Power's firm interstate gas transportation open positions have been reliably met by purchasing firm delivered gas. Nevada Power will continue to purchase firm delivered gas to close any open gas transportation positions during the action plan period.

Sierra: Sierra evaluated the following three scenarios: 1) normal weather conditions; 2) cold winter weather conditions (based on 1 in 10 peak HDD); and 3) extreme weather conditions (based on 71.8 heating-degree-days). The key finding from this analysis is that Sierra has enough 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 the ON Line. However, during an extreme winter weather scenario approximately 80 percent of the firm gas transport capacity will be used to supply the LDC requirements, limiting the availability of Sierra's natural gas-fired generation plants. In the extreme weather case, the majority of the electric requirements will need to be met with a combination of fuel other than gas, such as purchased power, renewable energy, and inter-company exchange from the southern system.

Sierra's analysis demonstrates that it has adequate gas transportation capacity and should maintain that capacity. Adding additional capacity would mitigate a remote loss of load risk but would increase costs. However, reducing capacity would increase the risk of loss of load in the winter to a level that is unacceptable.

9. Q. PLEASE DESCRIBE THE RESULTS OF PRODUCTION COST MODELING AND EXPLAIN WHY THE COMPANIES ARE NOT MODIFYING THE GAS TRANSPORTATION PLAN.

A. Both Nevada Power and Sierra need to have natural gas delivered to generation power plants, but Sierra also must serve its LDC customers. The PROMOD analysis shows under normal weather conditions, Nevada Power has a shortage of gas transportation capacity to deliver all of the gas volumes needed for the operation of the gas generating units, while Sierra has an adequate amount of capacity to fulfill the needs of both the generating units and LDC. The gas transportation contracts are critical to system reliability and it is important to maintain the Companies' contracted capacity to serve future loads.

Nevada Power: Nevada Power's projected gas requirement under normal and extreme weather conditions shows an open position with respect to interstate gas transportation; however, Nevada Power continues to be able to purchase delivered gas (i.e., gas supply plus transportation), to reliably meet the open positions with respect to interstate gas transportation. It should be noted that delivered gas is subject to the availability of willing counterparties and carries some market pricing and availability risk. Nevada Power will continue to evaluate the need for additional transportation capacity.

Sierra: Sierra's projected gas requirement under extreme weather conditions maximizes the use of all its firm transportation capacity. Failure to renew the gas transportation contracts that are up for renewal in the planning period would place Sierra's customers at greater risk of a curtailment to the LDC due to a lack of gas supply, which would result is a very high consequence event. Furthermore, by not renewing the contracts, Sierra would lose the option of renewing the contracts in subsequent years, and thus, risk losing future access to the pipelines.

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

A. Yes.

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

Employment History

NV ENERGY

GAS SUPPLY PLANNING LEAD – RESOURCE PLANNING DEPARTMENT – 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

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: September 1, 2022

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

2022 Energy Supply Plan
Docket No. 22-09___

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" or "NV Energy"). 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 analyses. I have also held the Consultant Staff position in the Demand Side Management department at NV Energy. More details regarding my professional 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, and 22-03024.

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

A. I sponsor the following sections in the Companies' Energy Supply Plan Update for 2023-2024 ("ESP"):

Section 3.A. ("Market Fundamentals")

Section 3.B. ("Fuel and Purchased Power Price Forecasts")

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

5. Q. PLEASE BRIEFLY DESCRIBE THE NATURAL GAS AND PURCHASED POWER PRICE FORECASTS USED IN THE ESP.

A. The ESP base power and natural gas price forecasts were developed using a 20-day average of market-based price quotes from April 2022. Quotes for natural gas are obtained from Argus Media. Quotes consist of observed transactions at the following trading hubs: Henry Hub, Northwest Pipeline Rockies, SoCal Border, Malin, El Paso Permian, Alberta – Nova Inventory Transfer, El Paso San Juan, and Sumas. Quotes for power at Palo Verde, Mead, California-Oregon Border, Mid-Columbia, and Four Corners trading hubs are also obtained from Argus Media.

6. 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 in order to determine how the total fuel and purchased power costs could vary under two extreme 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). The development of the high and low power price curves involves taking the respective high and low natural gas price forecast and multiplying it with the heat rates from the market-based price quotes. The final high and low power price curves are produced by adding the spark spread value that was calculated in the base case power price forecast.

7. Q. HOW DO YOU CAPTURE CAPACITY COSTS FOR PURPOSES OF THE POWER PRICE FORECAST?

A. Wood Mackenzie's ("WoodMac") regional power price forecast represents day-ahead firm energy prices; it does not explicitly include the full cost of new capacity additions that would be required to ensure resource adequacy over the forecast period. The regional price forecast is used by the PROMOD model to economically dispatch market purchases against internal generation, while the capacity price forecast (dollars per kilowatt-year) is multiplied by the Companies' open capacity position as an additional fixed fuel and purchased power cost.

8. Q. WHAT IS THE SOURCE OF THE COMPANIES' LONG-TERM CAPACITY PRICE FORECAST?

A. The Companies have utilized WoodMac's capacity price forecast in the preparation of the 2022 Joint ESP Update. As part of its Long-Term Outlook, WoodMac prepared an estimate of the levelized cost of new entry ("CONE") for the installed cost of future combined cycle and combustion turbine generation. The CONE is an estimate of the annual fixed costs associated with owning and operating a new generating facility (*i.e.*, exclusive of variable costs such as fuel and emissions). WoodMac then calculates the capacity price forecast (in dollars per kW-year) as the difference between the CONE and the net energy and ancillary services margins reflected in the wholesale power price forecast.

9. Q. DID THE COMPANIES FOLLOW THE GUIDELINE AGREED UPON IN DOCKET 21-03024 PERTAINING TO HIGH AND BASE PRICE FUEL AND PURCHASED POWER ("F&PP") FORECASTS?

A. Yes, the Companies have followed the guideline agreed upon in docket 21-03024 pertaining to high and base price F&PP forecasts. Since the high price F&PP forecast filed in first Amendment to the 2021 IRP is higher than the base price F&PP forecast filed in this ESP Update, the high price F&PP forecast was used for production cost modeling in 2022 and in 2023.

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

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

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

12. 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.

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

A. Yes, it does.

Statement of Qualifications

Zeljko Vukanovic **August 31, 2022**

<u>Professional Experience</u>

2019 To Date **Market Fundamentals Lead, Resource Planning and Analysis**
NV Energy

Develops and maintains proprietary perspective on regional gas and power market factors and fundamental price forecasts.

2017-2019 **Valuation and Planning Specialist, Resource Planning and Analysis**
NV Energy

Used market fundamentals analysis to resolve complex pricing, financial, economic, regulatory or legislative issues.

2012-2017 **Staff Consultant, DSM Planning**
NV Energy

Project Manager for Demand Side Management ("DSM") portion of Integrated Resource Plan ("IRP"), DSM Electric and Gas Annual Update Reports, and DSM portion of Renewable Portfolio Standard ("RPS") Annual Report.

2010-2012 **Senior Consultant, DSM Planning**
NV Energy

Responsible for optimizing the portfolio of DSM electric and gas programs with a goal of maximizing customer and shareholders benefits.

2006-2010 **Consultant, DSM Planning**
NV Energy

Responsible for quantitative and qualitative program evaluations with a goal of developing sustainable and cost effective DSM programs.

<u>Education</u>

Master of Science in Banking and Finance at the Boston University, 2011

Master of Business Administration at the University of Nevada at Las Vegas, 2008

Bachelor of Science in Business Administration, Megatrend University in Belgrade, Serbia, 2003

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

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ZELJKO G. 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: September 1, 2022

ZELJKO G. VUKANOVIC

NARRATIVE

NEVADA POWER COMPANY d/b/a NV ENERGY
SIERRA PACIFIC POWER COMPANY d/b/a NV ENERGY
JOINT ENERGY SUPPLY PLAN UPDATE FOR 2023-2024

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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 Update for 2023-2024 ("ESP Update"). In accordance with Nevada Administrative Code ("NAC") §§ 704.9506 and 704.9482, this ESP Update sets forth the Companies' power procurement plan, fuel procurement plan, and risk management strategy for calendar years 2023-2024. NRS § 704.9508 requires that this ESP Update be processed within 120 days of filing. The Companies request that the Public Utilities Commission of Nevada ("Commission") approve this ESP Update 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 energy 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 that the Commission:

Load Forecast

- Find that the load forecasts that were prepared for this ESP Update (the "2022 ESP Forecasts"), as described in Section 2.A. (Electric Load Forecast) and Technical Appendix Item IRP LF-1, meet the requirements of NAC §§ 704.9321(1) (because they are based on substantially accurate data and are adequately documented, justified, demonstrated and defended), 704.9482 (because the 2022 ESP Forecasts use base load forecasts), 704.9482(7) and 704.922 (because the technical appendices provide sufficient detail as to how the 2022 ESP Forecasts were prepared to facilitate the evaluation of the validity of the assumptions and the accuracy of the data used).

- Find that the 2022 ESP Forecasts are suitable for making planning decisions during the ESP Update period 2023-2024.

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 2023 and 2024 and begin filling the 2025 open position. This plan is consistent with the laddering strategy for closing the open power position, which was most recently approved in Docket No. 21-06001. The power procurement laddering strategy will be executed in coordination with the physical gas procurement plan.

    - Efforts by the Companies to negotiate and transact directly with counterparties as a supplement to the current request for proposal process. This would be to seek non-standard firm energy products in an effort to address short-term supply challenges during the early evening net demand peak period (i.e., the hours past the gross peak when solar production is very low or zero).

    - 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 no additional purchases will be required during the ESP period to meet the RPS.

- Find, consistent with NAC § 704.9494(3), that the power procurement strategy is prudent.

Physical Gas Procurement Plan[1]

- 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, subject to a cap on the premium, which can be exceeded with prior approval from the Risk Committee. Consistent with the Stipulation in Docket No. 09-09001, if the Companies exceed the premium cap, and the procured gas that exceeded the premium cap is not the least cost supply alternative, they will provide written notice to the Commission's Regulatory Operations Staff ("Staff") and the Bureau of Consumer Protection ("BCP").

- 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 3 with Southwest Gas Corporation. At Sierra, this requires authority to maintain a total of 33 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") and Northwest Pipeline LLC ("NWPL") 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 $112.8 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 Update period. The Companies will continue to monitor the natural gas

[1] The Companies' "fuel procurement plan" consists of several distinct elements; namely, the physical gas procurement plan, the gas transportation plan, the gas hedging plan and the coal procurement plan.

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.

Coal Supply Plan

- Acceptance and approval of a coal supply plan for Sierra. The coal supply plan considers current and projected coal unit operations and the level of uncertainty surrounding these operations, as well as market conditions. The coal supply plan proposes Sierra continue to fill North Valmy Generating Station's ("Valmy") coal requirements with short term supply contracts.

- An affirmative finding consistent with NAC § 704.9494(3) that the coal procurement 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.

- The Commission's order approving the stipulation in Docket No. 22-03024 for the Companies to provide an update on the White Pine Pumped Storage Hydro project.

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 2021 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, coal price forecasts, natural gas price forecasts, power price forecasts, large customer load information, the proposed cap on premiums to be paid for physical gas supplies, and the production cost modeling outputs.

For more information on the Companies' request for a determination of prudence of the 2022 ESP Update see Section 8.

D. OVERVIEW OF THE ENERGY SUPPLY PLAN

1. POWER PROCUREMENT PLAN

Based on the 2022 ESP Load Forecasts, the Companies have open power positions in the summers of 2023-2024. 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 2023-2024 summer open positions with firm products prior to respective summers.

The Companies propose to implement a four-season laddering strategy to close the remaining open power positions in 2023-2024 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 2021 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 early evening net demand peak period (i.e., the hours past the gross peak when solar production is very low or zero). 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 Update period.

The Companies anticipate meeting their RPS credit obligations throughout the ESP Update planning period. This ESP Update 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 Nevada Power will continue repaying its outstanding credit obligation to the joint pool for the benefit of Sierra.

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.

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 two interstate pipelines, Great Basin and Tuscarora. 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 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.

The Companies are seeking approval to maintain their current natural gas transportation portfolios. The contracts are listed in Figures ESP-38 and ESP-39. 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 Update 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. COAL SUPPLY PLAN

The coal requirements for Valmy are discussed in Section 2.H.

Valmy's coal requirements will be filled through request for proposals ("RFPs") transmitted to a list of qualified suppliers. Depending on available supply, short term contracts of two years and under will be considered to fill Valmy's coal supply needs.

4. 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 7.

5. 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 2022 ESP Load Forecast utilizes the same forecast filed as part of the Third Amendment to the 2021 IRP Load Forecast ("2021 IRPA 3rd Forecast"). The forecast was completed in May 2022, and using data through December 2021 begins with the calendar year 2023 through the 20 years ending 2042. The sections below provide a brief summary of the data, methodology, and results which are identical to the forecast filed in the 2021 IRPA 3rd Forecast.

Load Forecast Summary.
The NV Energy forecasted non-coincident peak is 8,097 megawatts ("MW") in 2023 (6,131 MW at Nevada Power and 1,966 MW at Sierra). The Companies' forecasted annual energy is 32,411 gigawatt-hours ("GWh") in 2023. The updated forecasts include adjustments related to the following main components: Demand Side Management ("DSM"), Demand Response ("DR"), solar photovoltaic ("solar PV") Net Energy Metering ("NEM") reductions, reductions for customers taking service under NRS Chapter 704B (Distribution Only Service – "DOS"), electric vehicle growth, and large customer changes.

Load Forecast Process.
The forecast database utilizes historical data through December 2021. For both Sierra and Nevada Power, electric sales and customers' monthly econometric models are still estimated for each of the three primary rate classes: residential, small ("Small C&I") and large commercial and industrial ("Large C&I"). For the residential and small commercial classes, separate models are estimated for customer counts and average use per customer, and total sales are calculated based on the customer count multiplied by average use per customer. Large C&I usage models are at the total sales level due to the diversity of usage levels across the customers in the class.

For Sierra, the Large C&I model excludes large mines and other large customers, which are individually forecasted based on the Companies' Major Account Executives, Economic Development and Energy Delivery personnel, and customer input related to changes in usage and maximum demand over the next several years. For Nevada Power, new large customers are added using the same methodology as Sierra. New large customer usage is added separately from the regression sales results as necessary. Other classes, including public authority, street lighting and irrigation sales are forecasted based on recent historical data.

Population Forecast.
Nevada Power's models include a Clark County population forecast based on the historical population series (intercensal population series) from three sources: the State Demographer, University of Nevada, Las Vegas' Center for Business and Economic Research's ("CBER") long term forecast and S&P Global's IHS Markit. For 2022, the average of the three growth rates for Clark County was used. The forecast used the averaged growth rates from these three sources with minor adjustments to smooth the forecasted growth.

Sierra's models use northern Nevada's population history and forecast, which is Nevada minus Clark County's population. In the updated forecast, the Sierra historical population was developed from IHS Markit. For 2021, the forecast used the averaged growth rates from IHS Markit and the State Demographer's 2021 forecast with minor adjustments to smooth the forecasted growth.

DETERMINING NORMAL WEATHER

Following the methodology approved by the Commission, the updated sales forecast is based on a trended 20-year normal weather period of historical and forecasted "normal" monthly heating degree days ("HDD" or "HDDs") and cooling degree days ("CDD" or "CDDs"). Normal weather involves determining the number of monthly HDD and CDD, and peak day temperatures. For the 2022 ESP Load Forecast, trended normal CDD and HDD were developed by regressing temperature on time, extending the regression into the future and converting to CDD and HDD for monthly sales models. See the technical Appendix LF-1 for more details.

Summer maximum average daily temperatures were used to determine the forecasted peak temperature. For Sierra, the 20-year average of the maximum summer daily average temperature was used for the peak forecast. For Nevada Power, the last five years of maximum summer daily average temperatures were used because the 20-year average did not produce a peak forecast high enough to reflect recent Nevada Power peaks.

NO NEW IMPACTS FROM BEHIND THE METER ENERGY STORAGE

The Companies made no adjustments to the updated forecast for energy storage at this time. Given the limited adoption of energy storage devices (1,062 customers as of July 2022), there is not enough data to determine the peak and hourly load impacts, as the impacts of energy storage will be immaterial until the adoption rates increase significantly.

IMPACTS ON ANNUAL ENERGY SAVINGS FROM AMENDED DSM ACTION PLAN

In the 2022 ESP Load Forecast, the incremental reduction in load attributed to DSM is based on estimates calculated in February 2022. These forecasted reductions are based on a goal of 1.10 percent (including DR) of forecasted sales for each company. This is the same as the 1.10 percent reduction (including DR) that was used for the 2021 Joint IRP load forecast approved in Docket No. 21-06001.

UPDATED DATA FROM ROOFTOP SOLAR PV PROGRAMS

The Companies made reductions in system demand and energy requirements to account for energy produced from private generation (i.e., solar PV) that is used by the customer at their premises. Projected incremental peak reductions of 133 MW at Nevada Power and 7 MW at Sierra by 2025 are based on the installed capacity of 286 MW and 24 MW for each respective company. More discussion of the impact of net metering on the load forecast is contained in Technical Appendix Item LF-1.

IMPACTS OF UPDATE TO MINING INDUSTRY FORECASTS

Consistent with the impacts captured in the 2021 Joint IRP, mining load in Sierra's territory declines by approximately 1,100 GWh in the forecast due to Nevada Gold Mines (f/k/a Newmont) moving to DOS as of February 2022. More details of the mine load forecast are contained in Technical Appendix LF-1

FORECASTS OF LOAD FOR OTHER LARGE CUSTOMERS

Details of individually forecasted customers in Sierra's service territory can be found in Technical Appendix LF-1.

In Sierra's service territory, the customer forecasts that are added individually include Queenstake, Coeur Rochester, Round Mountain Gold, Hycroft, Klondex-Firecreek, Barrick Arturo, Nevada Copper, Marigold Mining, Nevada Cement, Empire Mining, Eagle Picher, Rawhide Mining, Florida Canyon, James Hardy, USAF, Tesla, Google, Apple, Fulcrum, Mt. Elbert, Ormat, Patua Project, and Brady Power Partners.

In Nevada Power's service territory, the three large customers that were added outside the model were Allegiant Stadium, Google, Resorts World, and Fountainebleau.

NO NEW IMPACTS FROM DOS CUSTOMERS

The Companies 704B Eligible Loads remain the same as filed in the 2021 Joint IRP. The proposed amounts are 97,172 megawatt-hours ("MWh") at Nevada Power and 0 MWh at Sierra (due to import capacity constraints) for customers eligible to choose another energy provider in this forecast. More details of these forecasts are contained in Technical Appendix LF-1.

IMPACTS FOR ELECTRIC VEHICLES

Due to a combination of more aggressive programs offered by the Companies and Nevada state policy goals encouraging electric vehicle use, the forecast for this ESP assumes that electric plug-in vehicles, as a percentage of new vehicles in Nevada, will increase to 51.2 percent by 2030 and increase at 0.1 percent per year thereafter. This compares to the projection in the 2021 IRP Forecast that sales of such vehicles would constitute 11.2 percent of all new vehicle sales by 2030 and increase by 0.1 percent thereafter. In comparison to the 2021 Joint IRP, the updated statewide EV energy sales are estimated to increase 191 GWh by 2030 (combined for both Companies).

END-USE SATURATION AND EFFICIENCY TRENDS

The Companies combine end-use saturation and average stock efficiency projections to generate projected energy intensities. The census-level residential end-use saturations are calibrated to appliance ownership reported by Nevada Power and Sierra customers. Minor adjustments were made to smooth forecasted lighting for Nevada Power and lighting and miscellaneous intensities for Sierra. See Technical Appendix LF-1 for more details. Figure ESP-1 shows the monthly coincident peak load forecast for 2023.

FIGURE ESP-1
MONTHLY NV ENERGY PEAK LOAD FORECAST (2023)

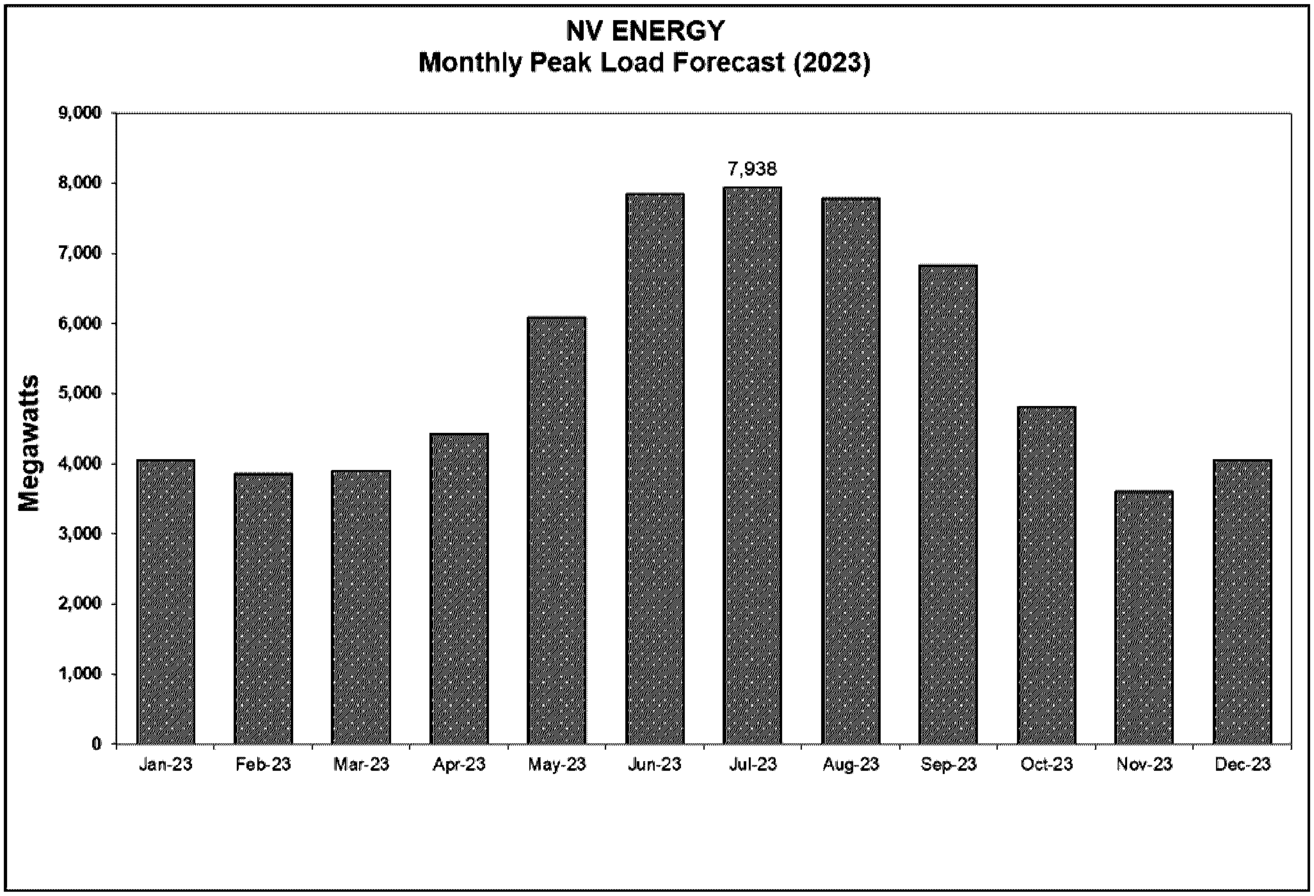


Figure ESP-2 shows the Companies' projected load duration curve for 2023. This is the distribution of load across the number of hours in the year and represents a load factor of 46.6 percent overall.

FIGURE ESP-2
NV ENERGY 2023 LOAD DURATION CURVE

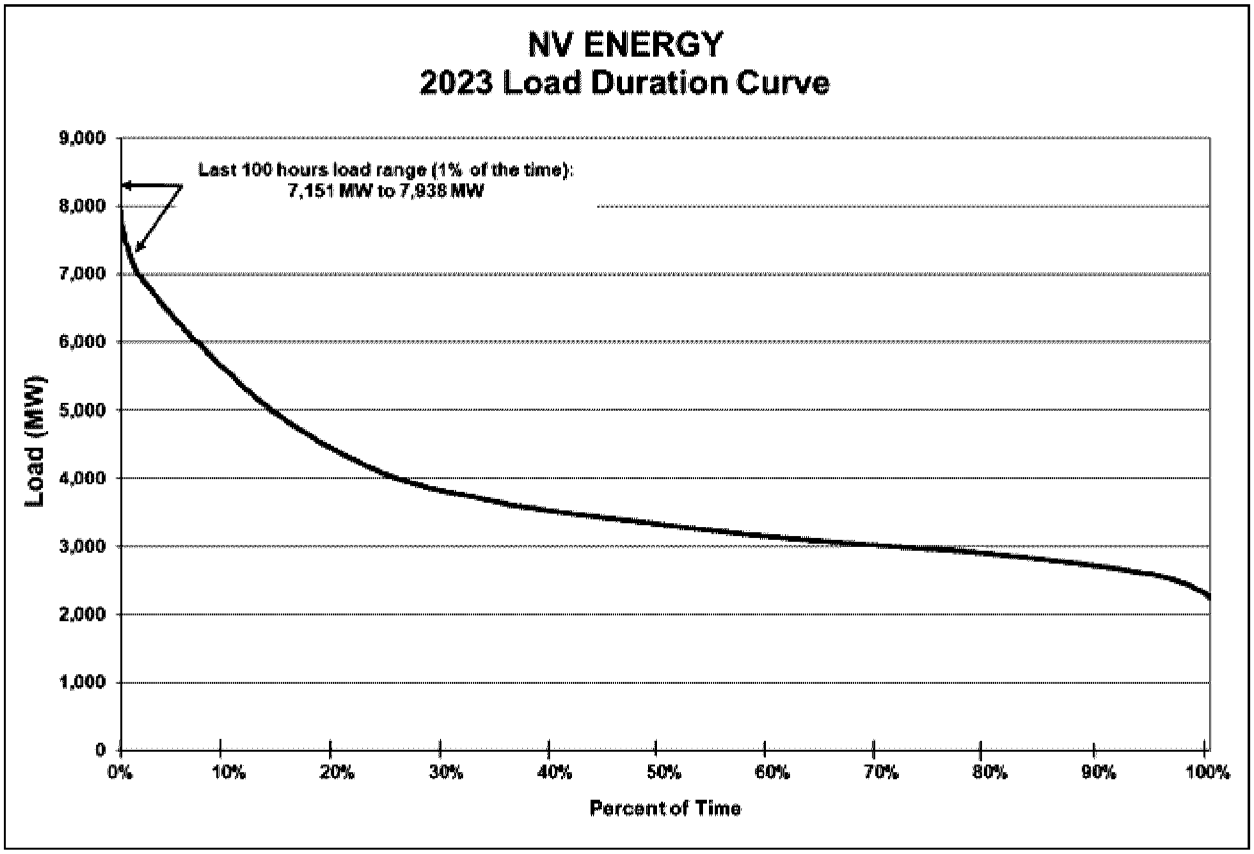
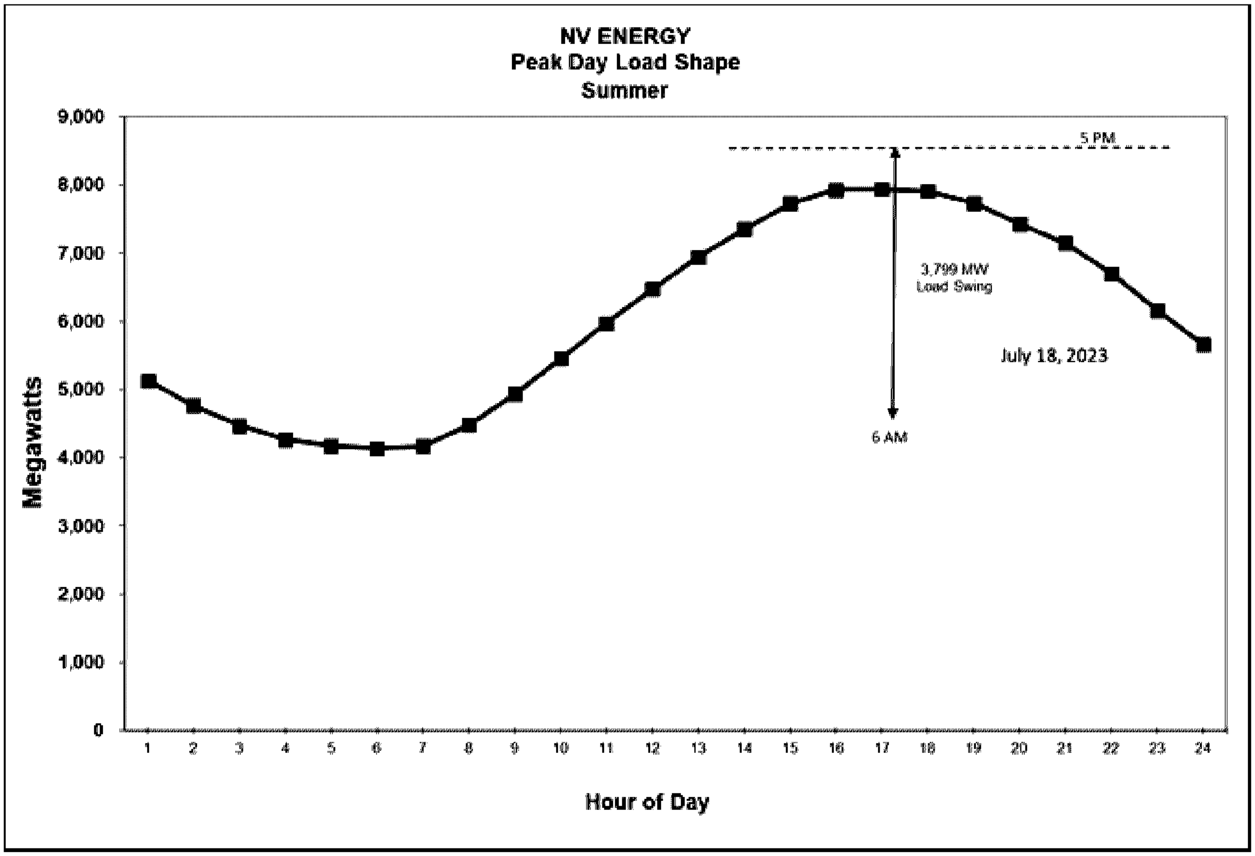


Figure ESP-3 reflects the expected fluctuation in hourly load during the summer peak day in July of 2023, which is expected to swing by about 3,799 MW, or 47.9 percent of the daily peak load. This load shape is representative of the near-term summer peak load shape for the Companies.

FIGURE ESP-3
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 margins ("PRM") of 16 percent. Due to the development of portfolios with large quantities of variable renewable resources in which available resources drop rapidly in the evening hours, the current paradigm, established in the 2021 ESP, evaluates the hour with the largest open position in addition to the traditional evaluation of the peak load hour to ensure reliability. Traditionally, these two hours were one and the same, but with increasing amounts of renewables, the later evening hours are showing significantly larger open positions. As such, the Companies close the largest open capacity position in the later evening hours rather than at the peak load hour. This paradigm shift increases reliability and reduces the risk of being reliant on short-term power markets in the evening hours.

In summer of 2023, and 2024 available resources are expected to be less than coincident system load over several hours. The largest open capacity positions under this new methodology are 1,409 MW in 2023, and 882 MW in 2024.

Figure ESP-4 ("L&R Tables") illustrates the current paradigm and details the resources necessary for the Companies to meet the forecasted customer load, including planning reserve requirements, by summer month and hours 5:00 pm through 8:00 pm for 2023-2024.

FIGURE ESP-4
2023-2024 LOADS & RESOURCES

2023	Hour Ending 5:00 pm				Hour Ending 6:00 pm				Hour Ending 7:00 pm				Hour Ending 8:00 pm			
	Jun-23	Jul-23	Aug-23	Sep-23	Jun-23	Jul-23	Aug-23	Sep-23	Jun-23	Jul-23	Aug-23	Sep-23	Jun-23	Jul-23	Aug-23	Sep-23
Maximum Coincident System Load	7,805	7,905	*7,905*	6,806	7,781	7,880	*7,880*	6,783	7,575	7,710	*7,710*	6,515	7,213	7,410	*7,410*	6,187
Planning Reserves 16%	1,249	1,265	*1,265*	1,089	1,245	1,261	*1,261*	1,085	1,212	1,234	*1,234*	1,042	1,154	1,186	*1,186*	990
Required Resources	9,054	9,170	9,170	7,894	9,026	9,141	9,141	7,868	8,787	8,944	8,944	7,558	8,367	8,595	8,595	7,177
Generation Existing - Coal & Gas	6,088	6,088	6,088	5,996	6,088	6,088	6,088	5,996	6,088	6,088	6,088	5,996	6,088	6,088	6,088	5,996
Generation Existing - PPAs	167	165	158	176	167	165	158	176	167	165	158	176	167	165	158	176
Market Transactions	874	824	724	724	874	824	724	724	874	824	724	724	874	824	724	724
Renewables	2,134	2,026	1,911	1,858	1,667	1,559	1,344	949	1,005	922	655	569	439	421	401	552
OATT Reserves	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*
Total Available Resources	9,174	9,015	8,792	8,711	8,706	8,546	8,224	7,755	8,043	7,910	7,535	7,375	7,478	7,408	7,281	7,358
Long/(Open) - Joint System	119	(156)	(379)	816	(321)	(595)	(917)	(114)	(744)	(1,034)	**(1,409)**	**(183)**	**(889)**	**(1,187)**	(1,314)	181

2024	Hour Ending 5:00 pm				Hour Ending 6:00 pm				Hour Ending 7:00 pm				Hour Ending 8:00 pm			
	Jun-24	Jul-24	Aug-24	Sep-24	Jun-24	Jul-24	Aug-24	Sep-24	Jun-24	Jul-24	Aug-24	Sep-24	Jun-24	Jul-24	Aug-24	Sep-24
Maximum Coincident System Load	8,008	8,081	*8,081*	7,173	7,986	8,049	*8,049*	7,165	7,779	7,884	*7,884*	6,889	7,438	7,599	*7,599*	6,532
Planning Reserves 16%	1,281	1,293	*1,293*	1,148	1,278	1,288	*1,288*	1,146	1,245	1,261	*1,261*	1,102	1,190	1,216	*1,216*	1,045
Required Resources	9,290	9,374	9,374	8,320	9,264	9,337	9,337	8,312	9,024	9,146	9,146	7,991	8,628	8,815	8,815	7,578
Generation Existing - Coal & Gas	6,091	6,091	6,091	5,999	6,091	6,091	6,091	5,999	6,091	6,091	6,091	5,999	6,091	6,091	6,091	5,999
Generation Existing - PPAs	167	165	158	176	167	165	158	176	167	165	158	176	167	165	158	176
Market Transactions	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168	168
Renewables	4,067	3,960	3,844	3,454	3,597	3,485	3,140	2,155	2,493	2,352	1,937	1,687	1,699	1,675	1,645	1,660
OATT Reserves	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*	*(90)*
Total Available Resources	10,403	10,295	10,172	9,707	9,933	9,820	9,468	8,408	8,829	8,686	8,264	7,940	8,035	8,010	7,972	7,913
Long/(Open) - Joint System	1,114	921	798	1,387	669	483	131	96	(195)	(459)	**(882)**	**(51)**	**(593)**	**(806)**	(843)	335

On 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 Companies' system) and external power contracts (outside 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. Total available resources (generation and purchases) are shown at the bottom section of the L&R Table, along with any open capacity positions. Short positions are indicated as negative values.

A number of the renewable resources that are currently under development are facing delays, shortfalls, and/or cancellations due to the various market conditions surrounding the solar PV and Battery Energy Storage System ("BESS") markets. As stated in the Stipulation resolving the Companies' First IRP Amendment,

> "…renewable resources that are currently under development could face delays, shortfalls, and/or cancellations, due to the various market conditions surrounding the solar PV and BESS markets, such as the 2020 global shutdowns, and the on-going lockdowns in places such as Shanghai caused by COVlD-19 which limit manufacturing and shipping; the March 2021 blockage of the Suez Canal that created a global supply chain disruption; and the March 2022 Department of Commerce's decision to investigate solar panels and modules from Cambodia, Malaysia, Thailand and Vietnam, which effectively froze the imports into the U.S. Recently, President Biden declared a 24-month pause on the implementation of the import tariff underlying the investigation, and invoked the Defense Production Act to drive U.S. manufacturing of solar panels.[2] It is not known how quickly the backlog of solar panel imports that was created by the Department of Commerce investigation can be cleared by the President's decree, or how long the global supply chain issues created by the global pandemic will last."[3]

While no project in the pipeline has formally notified the Companies that it will not go forward, in the past year several project developers have communicated difficulties obtaining major equipment at costs enabling them to fulfill their contracted obligations. Delays, shortfalls, and/or cancellations of any renewable resources currently under development would increase the Companies' open capacity positions.

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

[2] "Declaration of Emergency and Authorization for Temporary Extensions of Time and Duty Free Importation of Solar Cells and Modules from Southeast Asia" available at: https://www.whitehouse.gov/briefing-room/statements-releases/2022/06/06/declaration-of-emergency-and-authorization-for-temporary-extensions-of-time-and-duty-free-importation-of-solar-cells-and-modules-from-southeast-asia/.

[3] Docket No. 22-03024, July 13, 2022, Order, Attachment 1 at 7.

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,[4] minimum unit load levels, and must-run requirements).

The Companies will 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.

[4] 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.

D. RENEWABLE ENERGY PLANNING

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

- Full compliance with an escalating and compressed RPS schedule: 29 percent in 2022, 34 percent by 2024, 42 percent by 2027 and 50 percent by 2030;

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

- Developing a long-term strategy to build a generating portfolio that is capable of delivering 100 percentage carbon-free energy to all customers.

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 or one kWh of energy saved through an efficiency program. Similarly, one MWh of energy from renewable resources or savings from an efficiency program would result in one thousand PCs, or a "kPC."

In their most recent RPS Annual Compliance filing, Docket No. 22-04016, Nevada Power and Sierra both exceeded their respective 2021 RPS credit requirements of 24 percent. Nevada Power ended 2021 at 30.1 percent, a record for Nevada Power, while Sierra ended 2021 with 31.9 percent. Both utilities are also currently well positioned to exceed the 2022 RPS standard of 29 percent. In March 2022, two new Sierra renewable facilities declared commercial operation. Dodge Flat, a 200 MW solar facility with 50 MW of storage capacity declared its commercial operation date ("COD") on March 2, 2022, and Fish Springs Ranch, a 100 MW solar facility with 25 MW of storage capacity declared COD on March 15, 2022. Both facilities will significantly boost the amount of renewable energy and associated energy credits available to power the energy needs of Sierra's customers.

Both Nevada Power and Sierra Pacific are projected to fully comply with the RPS for the ESP action period, 2023 and 2024. This statement does not mean that the RPS beyond the action period is without risk. There are currently ten pipeline projects with projected COD dates ranging from December 2022 to December 2024 (reference the table below). Those projects are critical in not only maintaining RPS compliance, but also in growing the overall amount of carbon-free energy that is available to meet the energy needs of our customers. While both Nevada Power and Sierra are currently well positioned to meet all near-term credit commitments (RPS, NV GreenEnergy

Rider ("NGR"), ESP and 704B obligations), experience has proven that renewable projects, both operating and pipeline, can be unpredictable. To that end, the Companies remain committed to exploring all options, including continuing to issue renewable energy RFPs, developing their own projects, and exploring short-term purchase agreements, to seek out renewable projects that can economically increase green generating capacity for the benefit of their customers.

TABLE ESP-5
NEVADA POWER / SIERRA PACIFIC PIPELINE PROJECTS

	Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	Energy / Capacity Allocation NPC	SPPC
1	Moapa (Arrow Canyon) Solar [a.]	Solar PV	19-06039	12/01/22	200	75	60	140
2	North Valley Geothermal	Geothermal	22-03024	12/31/22	25			25
3	Eagle Shadow Mountain	Solar PV	18-06003	03/01/23	300		300	
4	Southern Bighorn Solar Farm [a.]	Solar PV	19-06039	09/01/23	300	135	180	120
5	Chuckwalla	Solar PV	20-07023	12/01/23	200	180	200	
6	Boulder Solar III	Solar PV	20-07023	12/31/23	128	58	128	
7	Iron Point [b.]	Solar PV	21-06001	12/01/23	250	200	140	110
8	Dry Lake Solar	Solar PV	20-07023	12/31/23	150	100	150	
9	Hot Pot [b.]	Solar PV	21-06001	12/01/24	350	350	196	154
10	Gemini Solar [c.]	Solar PV	19-06039	05/01/24	690	380	690	
					2,593	1,478	2,044	549

a. The energy/capacity of the project as allocated between Nevada Power and Sierra per the order (Docket No. 19-06039)

b. The energy/capacity of the project as allocated between Nevada Power and Sierra per the order (Docket No. 21-06001)

c. 40 percent of the PCs derived from Gemini Solar are to be assigned to Sierra per the order (Docket No. 19-06039)

RPS Compliance Planning

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

- Existing power purchase agreements ("PPAs") expire in accordance with the contract terms and are not automatically renewed;[5]

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

- The Companies adjusted the expected amount of energy and PCs from renewable facilities for the period of 2022-2025 in cases where the historic generation, based on two or more years of data, consistently varied from that of the contractual or expected supply table. This is consistent with the methodology that the Companies used for the past several years in developing their IRPs and ESPs. This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-terms plans;

- The projected number of PCs derived from the Renewable Generations incentive programs plateaued in 2020 with the last of the incentivized solar systems now installed. Starting in 2021, the expected number of credits 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 facilities placed in service before December 31, 2015, qualify for the solar multiplier; facilities placed in service after do not qualify;

- The plan assumes that the percent of annual PC requirements met from demand side management ("DSM") measures are limited to no more than 10 percent of the credit total for 2022 through 2024 before dropping to zero effective 2025. The plan also assumes, based on current DSM kPC projections, that Sierra may not have a sufficient number of DSM PCs to completely fill the 10 percent cap in 2024;

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

- The plan assumes that generation from both company-owned solar PV systems and PPA projects would be degraded starting the year following the first full year of operation. Geothermal generation which utilizes geothermal brine in the generating process would continue to qualify for station usage credits, all other technologies would no longer qualify;

- The plan accounts for all Commission approved and existing NGR and Energy Supply Agreements ("ESAs") as of July 31, 2022, where PCs associated with all or a portion of the output from a renewable facility(s) have been assigned to a customer under the NGR, the Market Price Energy or Large Customer Market Price Energy tariffs, and therefore cannot be used by the Companies in meeting their RPS credit requirements;

- 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 plan includes Iron Point 250 MW PV with BESS and Hot Pot Solar 350 MW PV with BESS, with the energy and PCs split 56 percent Nevada Power and 44 percent Sierra;

- The plan includes the North Valley geothermal ("North Valley Geothermal" or "North Valley") PPA. North Valley Geothermal is a 25 MW geothermal plant with an estimated commercial operation date of December 31, 2022. Sierra will be the sole off taker of the energy and PCs. The total number of PCs from this project includes station usage PCs. Certain geothermal station usage, the energy for the extraction and transportation of geothermal brine or used to pump or compress geothermal brine, is eligible for certification under the NRS 704.78215(3)(b). Station usage PCs for this facility were estimated at 15 percent of net;

- The annual amount of energy produced by solar PV systems paired with BESS has been reduced to account for battery losses. The adjustment recognized that not all of the energy produced by PV arrays paired with energy storage will be delivered real-time to the grid. Some of the energy will be stored and dispatched later when needed. The process of charging and discharging the batteries will result in energy losses; and

- An adjustment has been added to the model to capture the generation and PCs lost due to curtailment. 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 curtailment numbers used to calculate RPS compliance for the ESP outlook are based on the long-term forecast. The long-term forecast uses a different time interval to calculate excess generation when compared to the short-term forecast which assumes that energy can only be purchased and sold in sixteen-hour blocks.

RPS Compliance Planning

As previously stated, in forecasting renewable generation for the ESP Update action period, the Companies took into account 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. Therefore, no modifications are made to the supply tables. 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, the Companies adjusted the expected amount of energy from certain renewable facilities, where historic generation varied more than six percent from that of the contractual or expected supply table. This adjustment applied to the 2022-2025 planning horizon.

Figure ESP-6 below is a summary of all projects and supply adjustments used in developing Nevada Power's RPS outlook. Note, the list below only includes projects that were approved by the Commission as of July 31, 2022.

FIGURE ESP-6
NEVADA POWER SHORT-TERM SUPPLY ADJUSTMENTS

Facility	Actual / Projected COD	NamePlate (AC)	Resouce	Type	2022	2023	2024	2025	
						Action Period			
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%	100%	100%	
Jersey Valley	08/30/11	22.5	Geo	PPA	100%	100%	100%	100%	
McGinness Hills	06/20/12	96.0	Geo	PPA	100%	100%	100%	100%	
Salt Wells	09/18/09	23.6	Geo	PPA	76%	78%	80%	80%	a.
Stillwater (Geo & PV)	10/10/09	69.2	Geo/PV	PPA	86%	88%	73%	73%	a.
Tuscarora	01/11/12	32.0	Geo	PPA	100%	100%	100%	100%	
ACE Searchlight Solar	12/16/14	17.5	PV	PPA	100%	100%	100%	100%	
Arrowhead Canyon (Moapa) Solar	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%	
Boulder Solar III	12/31/23	128.0	PV	PPA	100%	100%	100%	100%	
Copper Mountain V	07/23/21	250.0	PV	PPA	100%	100%	100%	100%	
Chuckwalla	12/01/23	200.0	PV	PPA		100%	100%	100%	
Dry Lake	12/31/23	150.0	PV	PPA		100%	100%	100%	
Eagle Shadow Mountain	03/01/23	300.0	PV	PPA	100%	100%	100%	100%	
FRV Spectrum	09/23/13	30.0	PV	PPA	112%	112%	112%	112%	a.
Gemini Solar	05/01/24	690.0	PV	PPA			100%	100%	c.
Hot Pot	12/01/24	196.0	PV	PPA			100%	100%	e.
Iron Point	12/01/23	140.0	PV	PPA		100%	100%	100%	e.
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	92%	92%	92%	92%	a.
RV Apex Solar Power	07/21/12	20.0	PV	PPA	93%	93%	93%	93%	a.
Silver State Solar North	04/25/12	52.0	PV	PPA	100%	100%	100%	100%	
Southern Bighorn Solar	09/01/23	180.0	PV	PPA	x	100%	100%	100%	b.
Switch Station I	08/08/17	100.0	PV	PPA	100%	100%	100%	100%	d.
Techren 1	03/11/19	100.0	PV	PPA	92%	92%	92%	92%	a.
Techren 3	10/07/20	25.0	PV	PPA	100%	100%	100%	100%	
Techren 5	12/31/20	50.0	PV	PPA	100%	100%	100%	100%	
Apex Landfill	03/01/12	12.0	LFG	PPA	50%	50%	50%	50%	a.
WMNRE Lockwood	04/01/12	3.2	LFG	PPA	100%	100%	100%	100%	
Goodsprings	12/01/10	5.0	Waste Heat	NVE	100%	100%	100%	100%	
Spring Valley Wind	08/16/12	151.8	Wind	PPA	100%	100%	100%	100%	
		3,360.2							

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 NPC and SPPC (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. The energy and PCs from these projects will be split between NPC (56%) and SPPC (44%) (ref. Docket No 21-06001)

After applying the above supply adjustments, this planning approach resulted in an average 1.5 percent decrease in the total amount of projected net renewable energy over the 2023-2024 action period as compared to the PPA supply tables assuming no adjustments. The estimated amount of renewable energy available to Nevada Power in this year's ESP is shown in Figure ESP-7 below.

FIGURE ESP-7
NEVADA POWER PORTFOLIO CREDIT PROJECTIONS (kPCs) [1.]

		Action Period		
	2022	2023	2024	2025
Credit Requirement				
Nevada RPS Credit Target [2.]	6,017,454	5,963,767	7,124,694	7,245,667
NGR & Other non-RPS Credit Obligations [3.]	239,714	92,244	8,360	8,217
	6,257,168	6,056,011	7,133,054	7,253,884
Expected Credits all Sources - Unadjusted				
Energy / MW hrs [4.]	5,175,695	5,978,675	9,725,584	10,685,564
Station Usage, PC only, Co Owned, & Credit Allocations [5.]	26,512	(111,402)	(762,398)	(1,020,262)
DSM [6.]	601,745	596,377	712,469	0
RenewableGenerations [7.]	641,665	638,460	635,271	632,098
Carried Forword [8.]	1,273,682	1,462,132	2,508,230	5,686,102
Expected Credits, kPCs (All Sources, Unadjusted)	7,719,300	8,564,241	12,819,157	15,983,502
Projected Credit Surplus/<Deficit>	1,462,132	2,508,230	5,686,102	8,729,618
Expected Credits all Sources - Adjusted				
Energy / MW hrs [9.]	5,072,481	5,883,410	9,596,899	10,557,731
Station Usage, PC only, Co Owned, & Credit Allocations [5.]	26,512	(111,402)	(762,398)	(1,020,262)
DSM [6.]	601,745	596,377	712,469	0
RenewableGenerations [7.]	641,665	638,460	635,271	632,098
Carried Forword [8.]	1,273,682	1,358,917	2,309,752	5,358,938
Expected Credits, kPCs (All Sources, adjusted)	7,616,085	8,365,763	12,491,992	15,528,505
Projected Credit Surplus/<Deficit> w/Adj.	1,358,917	2,309,752	5,358,938	8,274,621

1 1 kWh = 1 PC, 1,000 kWh (1 MWh) = 1 kPC
2 Nevada RPS credit target by year 29%, 2022 - 2023, 34%, 2024 - 2026
3 Non-RPS credit 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 DSM credits are limited to 10% in 2022 - 2024
7 Credits incentive programs pursuant to NRS Chapter 701B
8 Excess credits carried forward for future compliance (note the plan assumes no excess credit sales)
9 Adjusted energy supply outlook after adjusting for historical performance

Figure ESP-8 is a summary of all projects and supply adjustments used in developing Sierra's ESP RPS outlook.

FIGURE ESP-8
SIERRA SHORT-TERM SUPPLY ADJUSTMENTS

Facility	Actual / Projected COD	NamePlate (AC)	Resouce	Type	2022 [a.]	2023	2024	2025 [a.]	
Beowawe	04/21/06	17.7	Geo	PPA	88%	88%	88%	88%	a.
Brady	07/30/92	24.0	Geo	PPA	100%	x	x	x	
Richard Burdette	02/28/06	26.0	Geo	PPA	77%	83%	84%	77%	a.
Galena 3	02/21/08	26.5	Geo	PPA	78%	78%	78%	78%	a.
North Valley Geothermal	12/31/22	25.0	Geo	PPA		100%	100%	100%	
Steamboat 2	12/13/92	13.4	Geo	PPA	73%	x	x	x	a.
Steamboat 3	12/19/92	13.4	Geo	PPA	80%	x	x	x	a.
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	01/31/22	200.0	PV	PPA	100%	100%	100%	100%	
Fish Springs Ranch	01/21/22	100.0	PV	PPA	100%	100%	100%	100%	
Hot Pot (44%)	12/01/24	154.0	PV	PPA			100%	100%	e.
Iron Point (44%)	12/01/23	110.0	PV	PPA		100%	100%	100%	e.
Nevada Solar One SPPC	06/27/07	22.1	CPS	PPA	91%	91%	91%	91%	a.
Arrowhead Canyon (Moapa) Solar	12/01/22	140.0	PV	PPA	100%	100%	100%	100%	b.
FT. Churchill PV	08/05/15	19.5	PV	PPA	81%	81%	81%	81%	a./c.
Boulder Solar II Apple	01/27/17	50.0	PV	PPA	100%	100%	100%	100%	c.
Southern Bighorn Solar	09/01/23	120.0	PV	PPA	100%	100%	100%	100%	b.
Switch Station 2	10/11/17	79.0	PV	PPA	100%	100%	100%	100%	c.
Techren Solar II	10/04/19	200.0	PV	PPA	100%	100%	100%	100%	c.
Techren Solar IV	10/07/20	25.0	PV	PPA	100%	100%	100%	100%	
Turquoise	12/04/20	50.0	PV	PPA	100%	100%	100%	100%	c.
Frank Hooper	06/23/86	0.8	Hydro	PPA	82%	82%	82%	82%	a.
New Lahontan TCID	06/12/89	4.0	Hydro	PPA	100%	100%	100%	100%	
TMWA Fleish	05/16/08	2.4	Hydro	PPA	100%	100%	100%	100%	
TMWA Verdi	05/15/09	2.4	Hydro	PPA	100%	100%	100%	100%	a.
TMWA Washoe	07/25/08	2.5	Hydro	PPA	74%	74%	74%	74%	a.
		1,540.4							

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 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 The energy and PCs from these projects will be split between NPC (56%) and SPPC (44%) (ref. Docket No 21-06001)

After applying the above adjustments, this planning approach resulted in an average 2.1 percent reduction in the total net amount of projected renewable energy over the 2023-2024 ESP action period as compared to the PPA supply tables assuming no adjustments. The estimated amount of renewable energy available to Sierra in this year's ESP is shown in Figure ESP-9 below.

FIGURE ESP-9
SIERRA PORTFOLIO CREDIT PROJECTIONS (kPCs)[1]

		Acton Period		
Credit Requirement	2022	2023	2024	2025
Nevada RPS Credit Target [2.]	2,231,922	2,329,232	2,845,981	2,945,589
NGR & Other non-RPS Credit Obligations [3.]	1,181,688	1,264,898	1,288,354	1,306,272
	3,413,610	3,594,130	4,134,335	4,251,861
Expected Credits all Sources - Unadjusted				
Energy / MW hrs [4.]	2,973,299	3,650,283	4,256,035	4,535,485
Station Usage, PC only, Co Owned [5.]	72,032	105,848	728,515	953,546
DSM [6.]	223,192	232,923	190,990	0
RenewableGenerations [7.]	128,798	129,440	128,795	128,153
Carried Forword [8.]	685,186	668,897	1,193,260	2,363,261
Expected Credits, kPCs (All Sources, Unadjusted)	4,082,507	4,787,391	6,497,595	7,980,444
Projected Credit Surplus/<Deficit>	668,897	1,193,260	2,363,261	3,728,583
Expected Credits all Sources - Adjusted				
Energy / MW hrs [9.]	2,845,777	3,566,649	4,174,852	4,454,978
Station Usage, PC only, Co Owned [5.]	72,032	105,848	728,515	953,546
DSM [6.]	223,192	232,923	190,990	0
RenewableGenerations [7.]	128,798	129,440	128,795	128,153
Carried Forword [8.]	685,186	541,375	982,104	2,070,922
Expected Credits, kPCs (All Sources, adjusted)	3,954,985	4,576,235	6,205,256	7,607,598
Projected Credit Surplus/<Deficit> w/Adj.	541,375	982,104	2,070,922	3,355,737

1 1 kWh = 1 PC, 1,000 kWh (1 MWh) = 1 kPC
2 Nevada RPS credit target by year 29%, 2022 - 2023, 34%, 2024 - 2026
3 Non-RPS credit obligations: 704B
4 Total renewable energy delivered to Sierra's system and available to meet Sierra retail load
5 Credits from station usage, credits from small NVE owned systems, credits from credit only agreements, credits repaid by Nevada Power
6 DSM credits are limited to 10% in 2021 - 2022, they are expected to total less than 10% in 2023 and 2024
7 Credits from incentive programs pursuant to NRS Chapter 701B
8 Excess credits carried forward for future compliance (note the plan assumes no excess credit sales)
9 Adjusted energy supply outlook after adjusting for historical performance

Nevada Power and Sierra will continue to closely monitor their RPS compliance outlooks recognizing that there is a myriad of factors, some outside of the Companies' control, which ultimately determine whether the Companies will have enough PCs to satisfy their RPS credit obligations and carbon-free generation goals. The objective is to never be put into a reactive position where the Companies must acquire a large number of PCs in a short time frame in order to maintain compliance. Time expands options. This increases the ability of the Companies to negotiate favorable contracts to acquire the renewable resources that are needed to meet the needs of customers and comply with all regulatory and internal requirements and towards achieving the goal of 100 percent carbon-free generation by 2050.

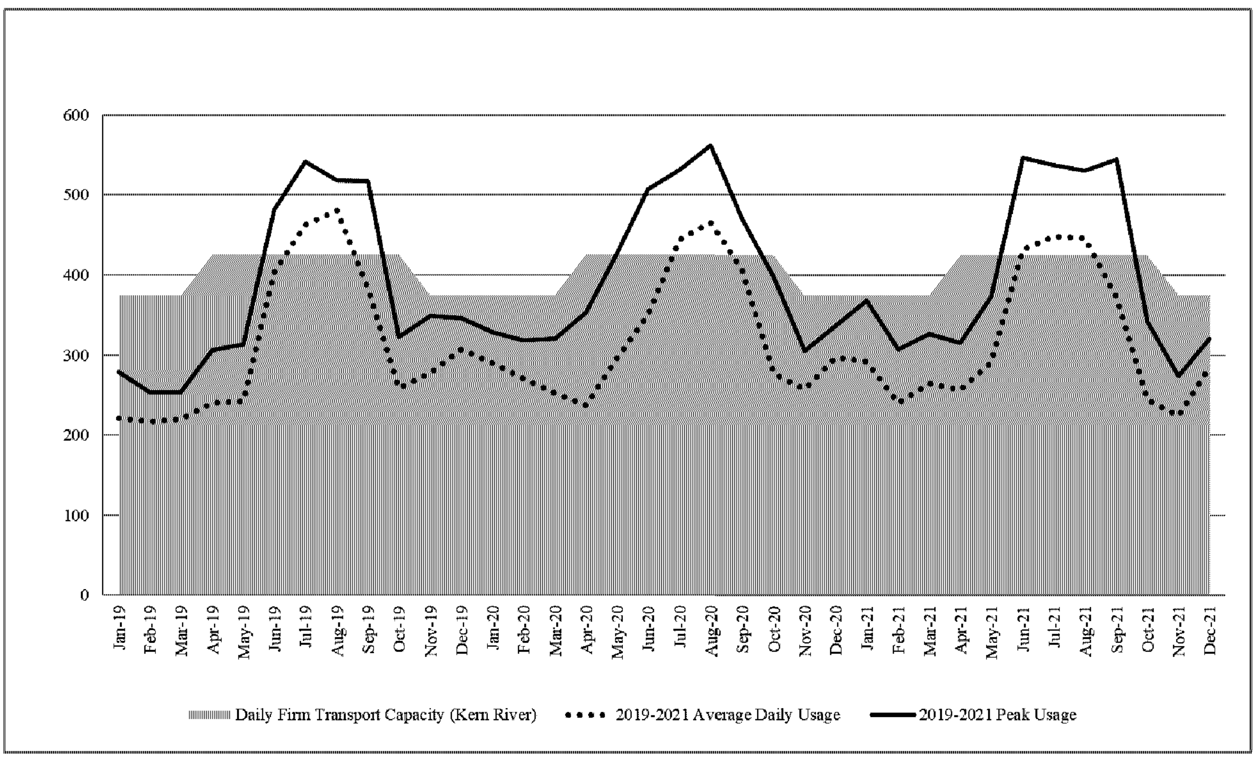
E. GAS TRANSPORTATION REQUIREMENTS

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-38 and ESP-39 respectively. The Companies are not proposing to execute any new gas transport contracts and are relying on rights of first refusal and annual evergreen rights to keep existing gas transport capacity rights in place.

For the ESP, the Companies utilized PROMOD, a security constrained 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 Sierra LDC with the One Nevada Transmission Line ("ON Line") in service.

Favorable natural gas pricing has led to increased utilization of natural gas-fired generation resources. As a result, Nevada Power's firm transportation capacity was fully utilized 77 days in 2019, 74 days in 2020 and 68 days in 2021, leaving open positions for firm interstate gas transportation in each year, as seen in Figure ESP-10.

FIGURE ESP-10
NATURAL GAS USAGE VS. TRANSPORT CAPACITY (MMBTU)



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

A load forecast was prepared for Nevada Power assuming both a hot summer and a cold winter (see Technical Appendix LF-1, Section VIII – Weather Scenario Forecast for Gas Transportation Analysis for more details). PROMOD was used to further evaluate projected firm gas transportation needs for the generation fleet. The time period of the analysis was January 2023 through December 2024.

The following two scenarios were evaluated:

1. Normal weather conditions and existing firm gas transportation contracts; and
2. Hot summer/cold winter weather conditions (based on 1 in 10 peak CDD and HDD) and existing firm gas transportation contracts.

The projected number of days Nevada Power will require deliveries in excess of the existing firm rights for natural gas transportation capacity under extreme weather are 13 days for 2023, and 25 days for 2024. Figure ESP-11 and Figure ESP-12 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-11
NORMAL WEATHER NATURAL GAS USAGE VS. TRANSPORT CAPACITY

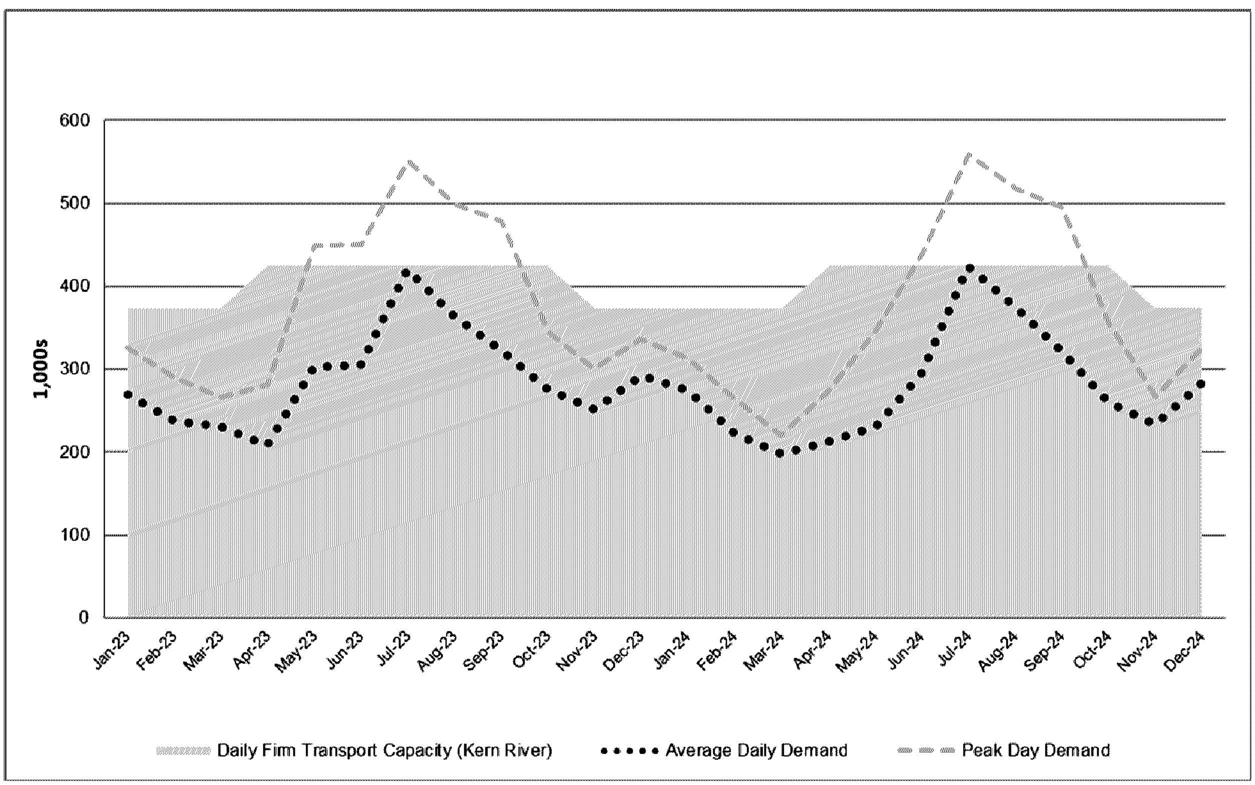
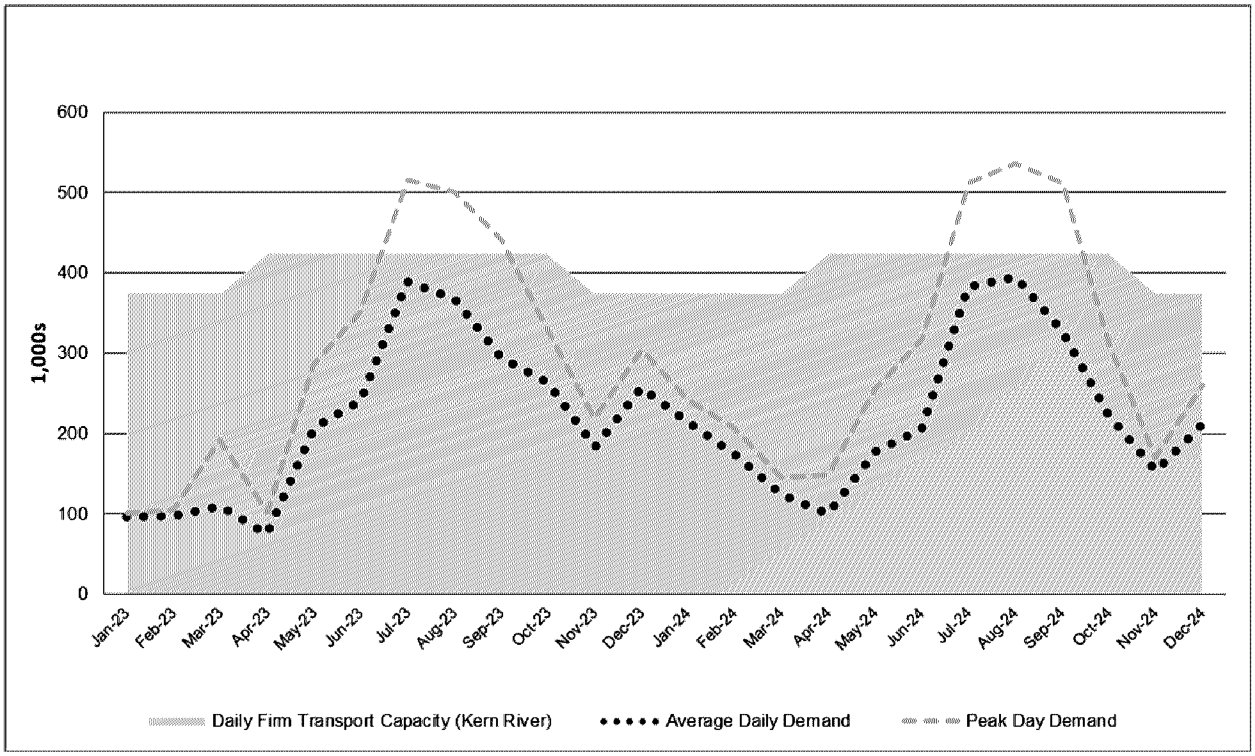


FIGURE ESP-12
EXTREME WEATHER NATURAL GAS USAGE VS. TRANSPORT CAPACITY



Sierra's peak day normal weather (base case) forecast has historically allowed a small open position with respect to firm interstate gas transportation, which can be reliably met by purchasing firm delivered gas. PROMOD was used to evaluate the system reliability and projected firm gas transportation needs for both the plant and LDC with ON Line in service. PROMOD was used to estimate system reliability, as quantified by loss of load hours ("LOLH") for both Nevada Power and Sierra, with the latter combining electric and LDC needs.

LDC natural gas requirements were first met 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 (beginning in December 2021 and through January 2024), as the LDC's recorded peaks have predominantly occurred in those two months. The following two 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).
3. Extreme weather conditions (based on 70 HDDs) and existing natural gas transportation contracts.

Figure ESP-13 shows the daily natural gas requirements projected for December/January along with the firm natural gas transportation available for the two scenarios for both the LDC and electric generating plants.

FIGURE ESP-13
SIERRA DAILY NATURAL GAS REQUIREMENT
FOR DECEMBER/JANUARY

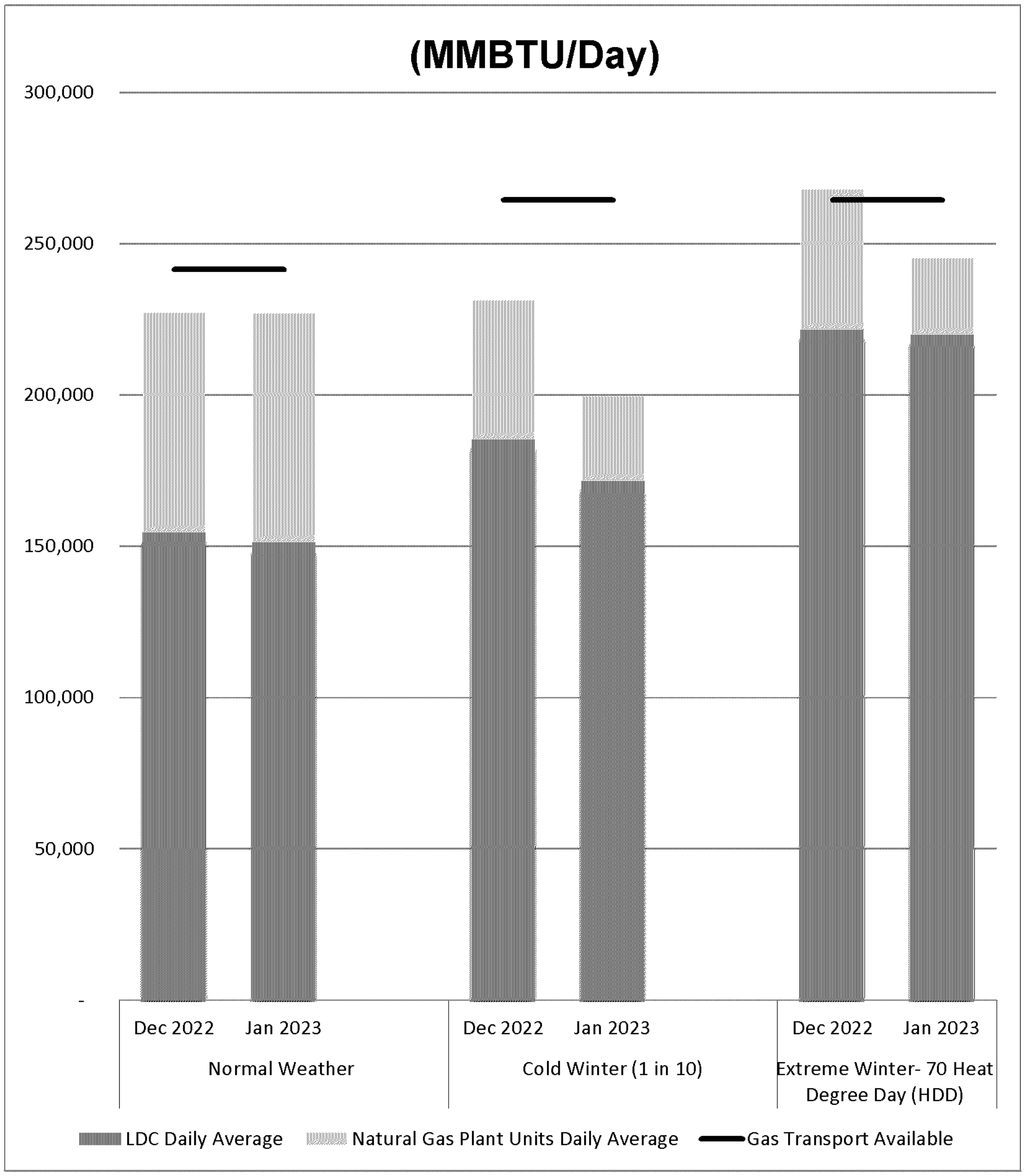
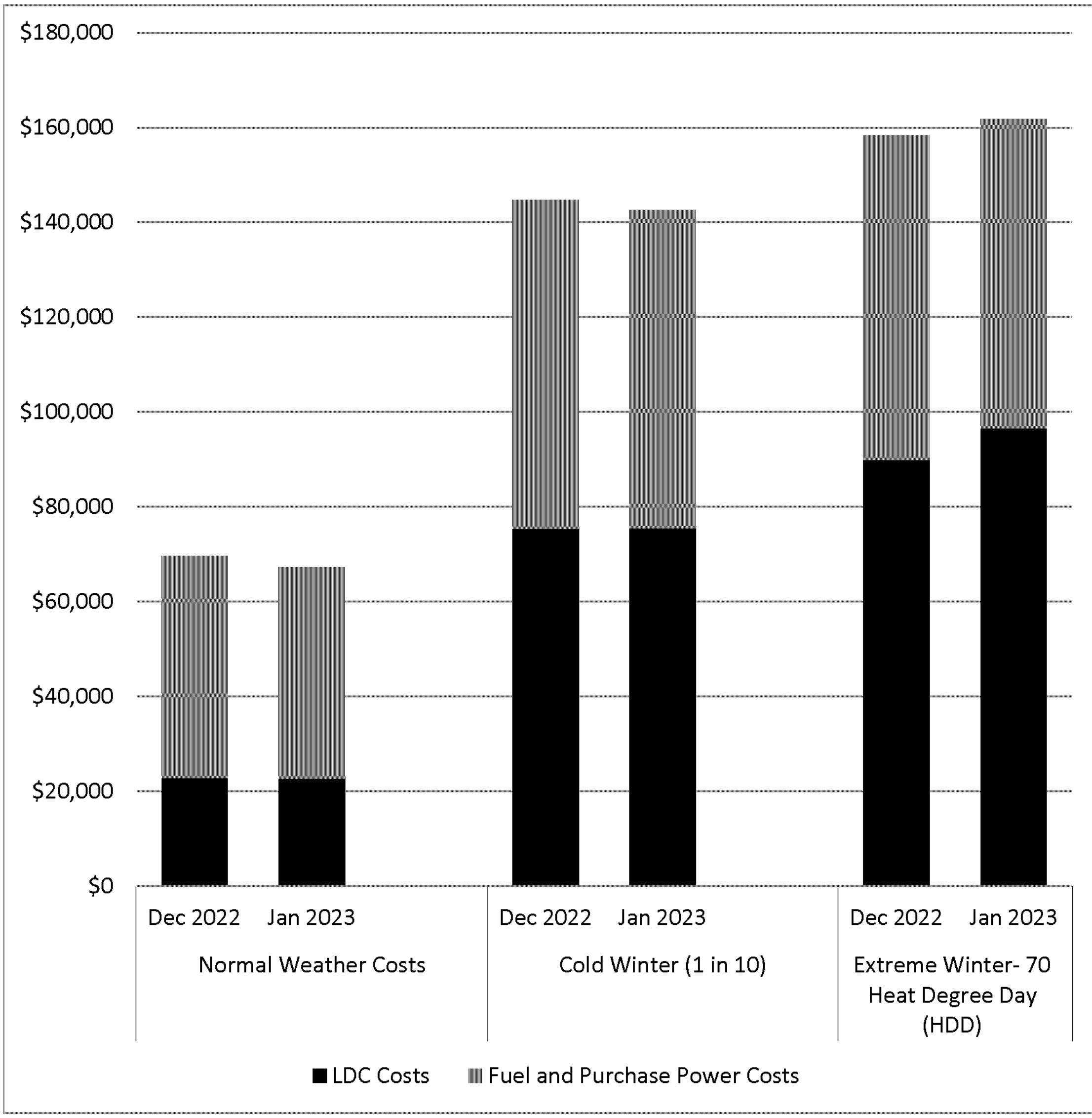


Figure ESP-14 shows the associated total costs of meeting the electric and natural gas requirements by the various sources for the two scenarios.

FIGURE ESP-14
SIERRA TOTAL COSTS ($000) – FUEL AND PURCHASE POWER AND LDC



The key finding from this analysis is that Sierra has enough 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 the ON Line. However, during an extreme winter weather scenario approximately 80 percent of the firm gas transport capacity will be used to supply the LDC requirements, limiting the availability of Sierra's natural gas-fired generation plants. In the extreme weather case, the majority of the electric requirements will need to be met with a combination of fuel other than gas, purchase power, renewable energy, and inter-company exchange from the southern system.

For the joint system in the extreme weather case, 15 LOLH was observed during December 2022 through January 2023 and 9 LOLH during December 2023 through January 2024 on the electric system in the two months studied.

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 and short December through February during normal weather conditions. Sierra has and 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 PROMOD to calculate the average daily gas requirements as illustrated in Figures ESP-15 and ESP-16.

FIGURE ESP-15
NEVADA POWER AVERAGE DAILY GAS REQUIREMENTS

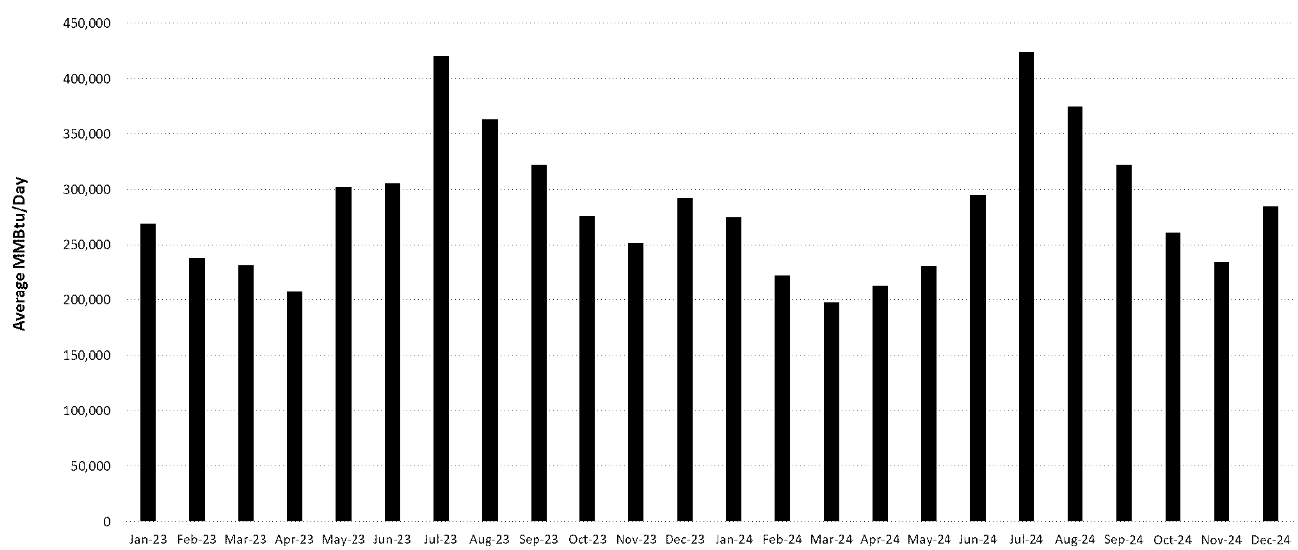
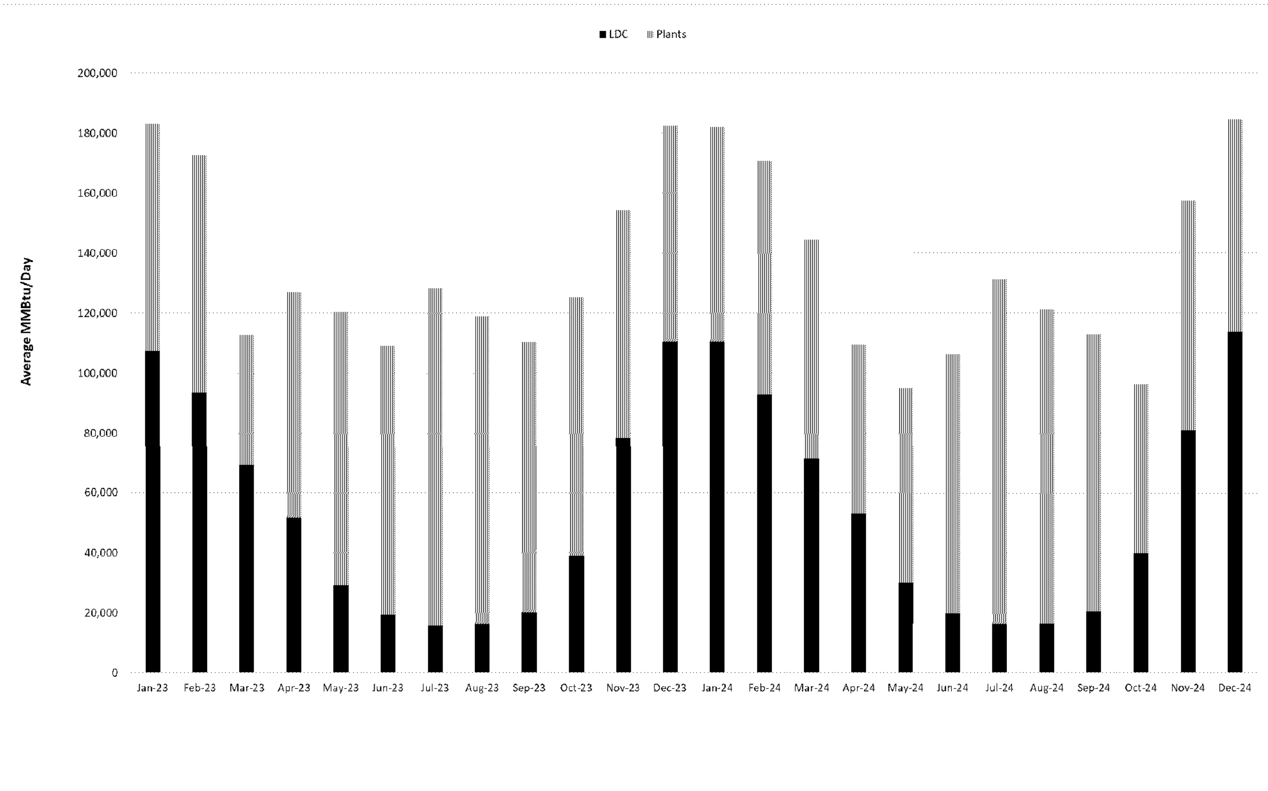


FIGURE ESP-16
SIERRA AVERAGE DAILY GAS REQUIREMENTS



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-17 shows the current approved physical gas volumes and future targets the Companies.

FIGURE ESP-17
PHYSICAL GAS SUPPLY UNDER CONTRACT (MMBTU/DAY)

Monthly NPC	Current Approved Volumes	Volumes Procured as of 7/1/2022	Current Target Procurement Level	Estimated Volumes to Be Procured in 2022 Q3 RFP	Estimated Total Volumes Procured After 2022 Q3 RFP	Estimated Pct of Approved Volumes Closed Following 2022 Q3 RFP
Jan-2023	275,000	206,500	75%	69,000	275,500	100%
Feb-2023	246,000	184,000	75%	62,000	246,000	100%
Mar-2023	207,000	155,000	75%	52,000	207,000	100%
Apr-2023	214,000	107,000	50%	54,000	161,000	75%
May-2023	333,000	166,500	50%	83,000	249,500	75%
Jun-2023	328,000	163,500	50%	83,000	246,500	75%
Jul-2023	422,000	210,500	50%	106,000	316,500	75%
Aug-2023	382,000	191,000	50%	96,000	287,000	75%
Sep-2023	303,000	151,000	50%	76,000	227,000	75%
Oct-2023	292,000	146,000	50%	73,000	219,000	75%
Nov-2023	269,000	67,000	25%	68,000	135,000	50%
Dec-2023	307,000	76,500	25%	77,000	153,500	50%
Jan-2024	283,000	146,000	50%	-5,000	141,000	50%
Feb-2024	231,000	67,000	25%	49,000	116,000	50%
Mar-2024	206,000	76,500	25%	27,000	103,500	50%

Monthly SPPC	Current Approved Volumes	Volumes Procured as of 7/1/2022	Current Target Procurement Level	Estimated Volumes to Be Procured in 2022 Q3 RFP	Estimated Total Volumes Procured After 2022 Q3 RFP	Estimated Pct of Approved Volumes Closed Following 2022 Q3 RFP
Jan-2023	179,000	134,000	75%	45,000	179,000	100%
Feb-2023	174,000	130,000	75%	44,000	174,000	100%
Mar-2023	143,000	107,000	75%	36,000	143,000	100%
Apr-2023	126,000	63,000	50%	32,000	95,000	75%
May-2023	112,000	56,000	50%	28,000	84,000	75%
Jun-2023	108,000	54,000	50%	27,000	81,000	75%
Jul-2023	127,000	63,000	50%	32,000	95,000	75%
Aug-2023	120,000	59,500	50%	31,000	90,500	75%
Sep-2023	109,000	54,500	50%	27,000	81,500	75%
Oct-2023	118,000	58,500	50%	30,000	88,500	75%
Nov-2023	157,000	39,000	25%	40,000	79,000	50%
Dec-2023	185,000	46,000	25%	47,000	93,000	50%
Jan-2024	184,000	46,000	25%	46,000	92,000	50%
Feb-2024	168,000	41,500	25%	43,000	84,500	50%
Mar-2024	146,000	36,000	25%	37,000	73,000	50%

The natural gas volumes shown in Figure ESP-17 are subject to the following explanations:

- Procured volumes in the table above are quantified at the "burner tip" and do not include an adjustment for pipeline retainage or losses. In order 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 Paiute and Tuscarora, subject to meeting any gas transport contractual obligations, such as operational flow orders issued by upstream and/or downstream pipelines.

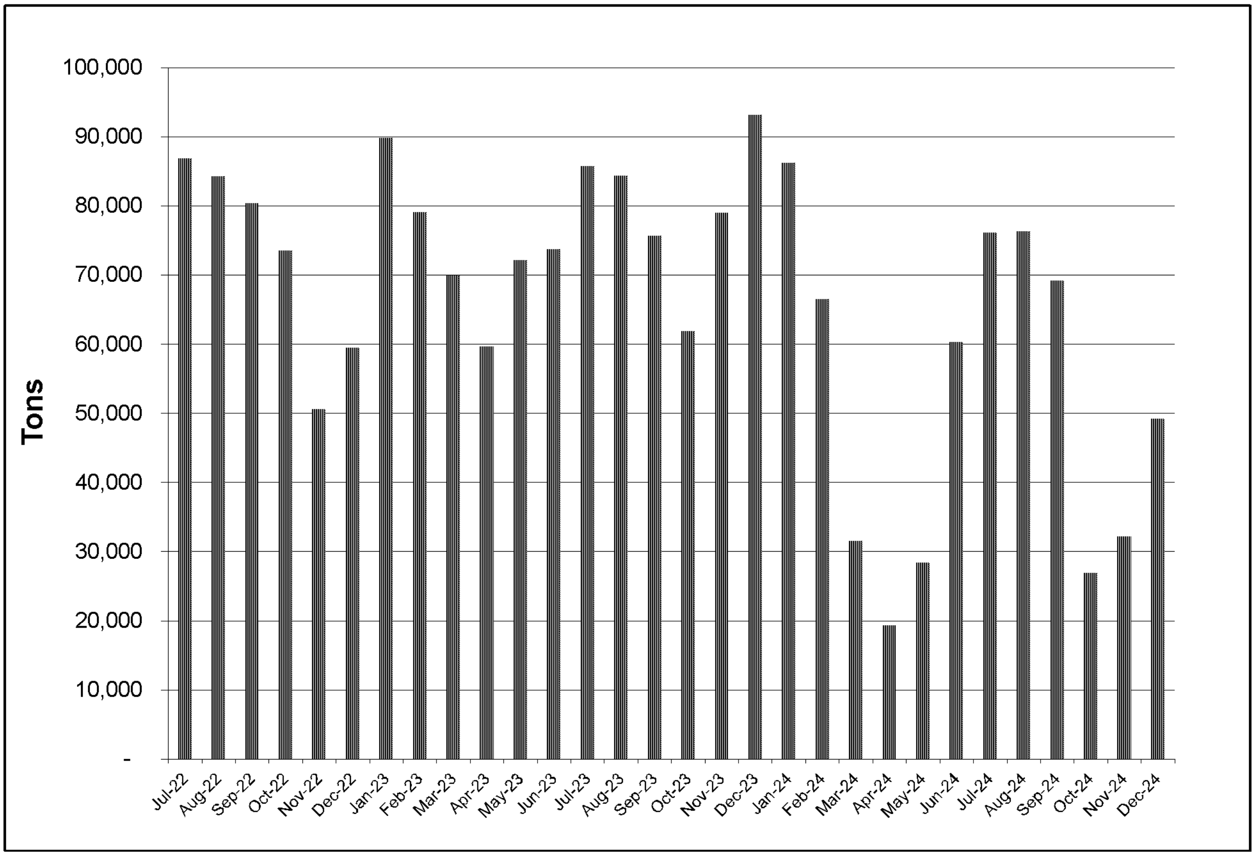
G. FINANCIAL GAS REQUIREMENTS

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

H. COAL REQUIREMENTS

Projected coal burn requirements for the ESP period are limited to Sierra's Valmy units and are shown in Figure ESP-18. For more information on Valmy operation, please see Section 6.

FIGURE ESP-18
VALMY COAL REQUIREMENTS



SECTION 3 - MARKET FUNDAMENTALS & PRICE FORECASTS

A. MARKET FUNDAMENTALS

1. WESTERN ELECTRIC COORDINATING COUNCIL AND ENERGY IMBALANCE MARKET

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.[6] Figure ESP-18 depicts the various NERC regions and sub-regions, including the WECC.

In order to conduct NERC reliability assessments, NERC further divides the REs into 20 assessment areas, also shown in Figure ESP-19 below. 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 four sub-regions: California/Mexico ("CA/MX"), the Northwest Power Pool ("NWPP"), which is further divided into the NW-Canada and NW-US areas, and the Southwest Reserve Sharing Group ("SRSG"). The NWPP sub-region also includes the Rocky Mountain Reserve Group ("RMRG") sub-region. 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. NWPP & RMRG area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. The Companies reside in the NWPP US & RMRG sub-region.

[6] https://www.wecc.org/Pages/AboutWECC.aspx

FIGURE ESP-19
NERC REGIONS AND SUB-REGIONS

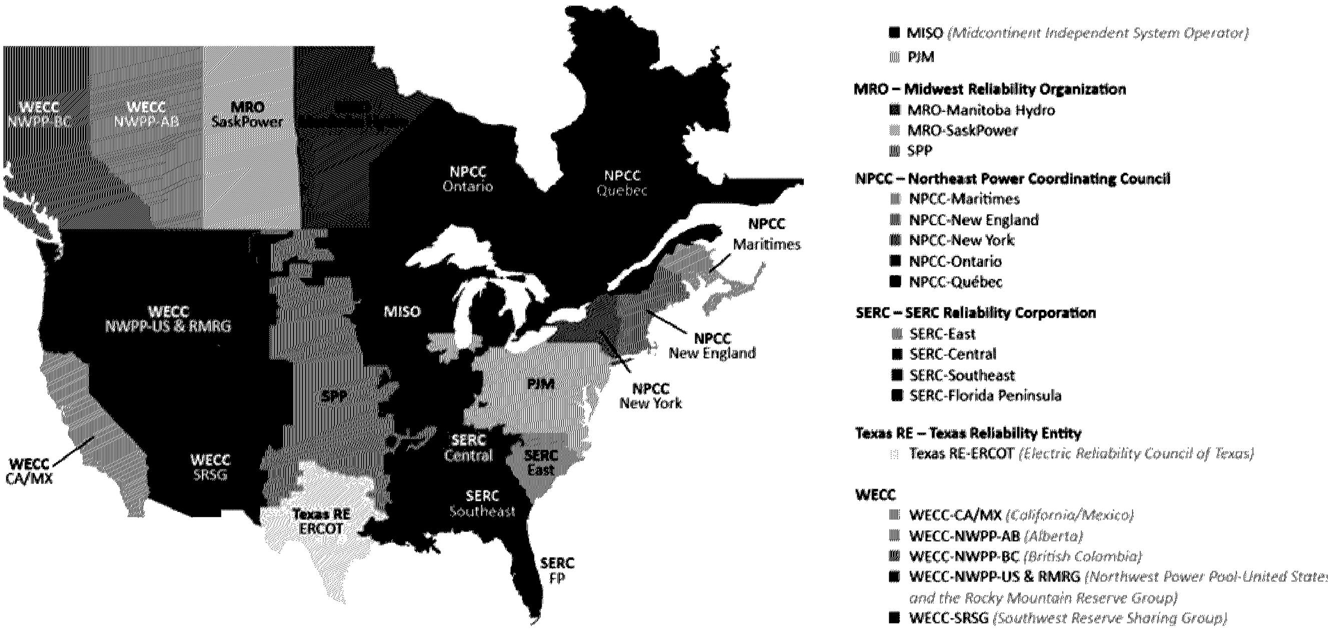


Figure ESP-20 shows the capacity composition in the NWPP and RMRG region and the prevalence of gas-fired and hydroelectric generation. [7]

FIGURE ESP-20
NWPP AND RMRG CAPACITY BY FUEL TYPE

WECC-NWPP & RMRG Composition (MW)										
Fuel	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	14,838	14,348	13,826	13,818	12,489	12,489	11,641	10,951	10,700	10,591
Petroleum	277	276	276	275	275	275	275	276	276	277
Natural Gas	29,751	29,799	29,791	29,646	29,557	29,353	29,011	28,981	28,710	28,483
Biomass	784	785	784	779	779	779	779	784	784	784
Solar	5,247	6,699	8,797	8,632	8,632	9,057	9,057	9,240	9,240	9,057
Wind	2,560	3,797	2,839	2,566	2,566	2,566	2,566	2,846	2,846	2,566
Geothermal	887	974	1,014	1,022	1,022	1,022	1,086	1,078	1,078	1,080
Conventional Hydro	20,383	22,275	22,777	20,402	20,403	20,622	20,622	22,420	22,992	20,605
Pumped Storage	326	347	359	326	326	326	326	345	359	326
Nuclear	1,095	1,099	1,097	1,081	1,081	1,081	1,081	1,097	1,097	1,097
Other	191	305	304	306	306	306	306	304	304	304
Total MW	76,339	80,703	81,865	78,853	77,436	77,875	76,749	78,322	78,386	75,169

[7] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.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.[8] 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 2022 EIM Benefits Report published by the CAISO estimates that the EIM has yielded more than $2.1 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 have been $4.41 million in first quarter of 2022. Sharing resources across a larger geographic area reduces greenhouse gas emissions by utilizing renewable generation that otherwise would have been turned off. The quantified environmental benefits from avoided curtailments of renewable generation from 2015 to-date reached 712,270 metric tons of CO_2, roughly the equivalent of avoiding the emissions from 149,752 passenger cars driven for one year.[9] A map of the active and pending EIM participants is provided in Figure ESP-21.

Participants - Active

- Bonneville Power Administration – entered 2022
- Tucson Electric Power – entered 2022
- Avista – entered 2022
- Tacoma Power – entered 2022
- NorthWestern Energy – entered 2021
- Los Angeles Department of Water & Power – entered 2021
- Public Service Company of New Mexico – entered 2021
- Turlock Irrigation District – entered 2021
- Salt River Project – 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

[8] https://www.westerneim.com/Pages/About/default.aspx

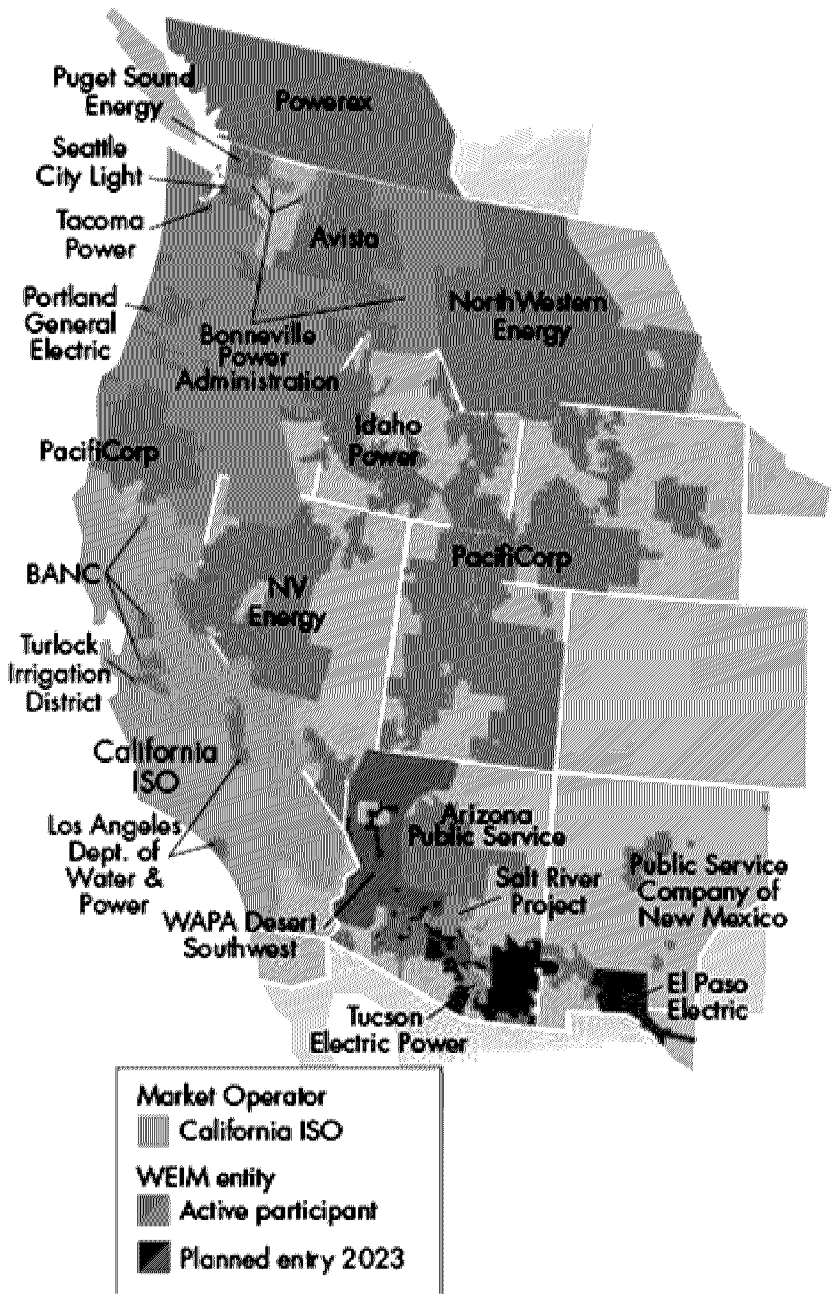
[9] https://www.westerneim.com/Documents/ISO-Western-Energy-Imbalance-Market-Benefits-Report-Q1-2022.pdf

- PacifiCorp – entered 2014
- California ISO – entered 2014

Participants - Pending

- Avangrid – entry 2023
- El Paso Electric – entry 2023
- WAPA Desert Southwest Region – entry 2023

FIGURE ESP-21
WESTERN EIM ACTIVE AND PENDING PARTICIPANTS



2. 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.

Planning Reserve Margins (Anticipated Reserve Margin or "AR" and Prospective Reserve Margin or "PR") 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 planning reserve margins relative to its Reference Margin Level[10] ("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.

On the basis of the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

- Adequate: AR[11] is greater than RML.
- Marginal: AR[12] is lower than RML and PR is higher than RML.
- Inadequate: Both ARs and PRs are less than the RML and Tier 3 resources are unlikely to advance.

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[10] 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 increase 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.

[11] This is the amount of anticipated resources less net internal demand calculated as a percentage of net internal demand.

[12] This is the amount of prospective resources less net internal demand calculated as a percentage of net internal demand.

The most recent forecast of these reserve margins from the NERC 2021 LTRA published in December of 2021 is shown in Figure ESP-22.[13]

FIGURE ESP-22
NWPP AND RMRG POWER SUPPLY ASSESSMENT

WECC-NWPP & RMRG Demand, Resources, and Reserve Margins (MW)										
Quantity	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Total Internal Demand	70,393	71,775	72,955	73,410	73,843	74,476	75,136	75,671	76,191	76,803
Demand Response	1,336	1,340	1,344	1,352	1,354	1,355	1,352	1,353	1,359	1,360
Net Internal Demand	69,058	70,435	71,611	72,058	72,490	73,121	73,784	74,317	74,831	75,443
Additions: Tier 1	2,335	4,531	6,095	5,992	5,993	6,636	6,700	6,844	6,873	6,698
Additions: Tier 2	254	1,177	1,350	1,324	1,324	1,324	1,324	1,345	1,349	1,325
Additions: Tier 3	180	306	2,620	2,575	2,739	2,739	2,918	3,680	5,439	5,399
Net Firm Capacity Transfers	7,556	7,008	6,096	7,655	7,317	6,425	6,447	9,180	8,701	6,280
Existing-Certain and Net Firm Transfers	81,560	83,180	81,867	80,517	78,760	77,664	76,496	80,658	80,214	74,751
Anticipated Reserve Margin (%)	21.5%	24.5%	22.8%	20.1%	16.9%	15.3%	12.8%	17.7%	16.4%	8.0%
Prospective Reserve Margin (%)	21.9%	26.2%	24.7%	21.9%	18.7%	17.1%	14.5%	19.6%	18.2%	9.7%
Reference Margin Level (%)	13.6%	15.2%	14.0%	13.7%	13.5%	13.4%	13.4%	13.8%	13.4%	13.0%

NWPP and RMRG sub-regions are assessed as *adequate* by NERC until 2028 and are expected to have sufficient generation to meet or exceed the RML for the seasonal peak hours represented in the assessment period for this particular on-peak assessment. This is based on expected levels of demand and resource availability.

However, measures of energy adequacy from the probability assessment ("ProbA"), which accounts for all hours are cause for concern. The two largest U.S. assessment areas in the WI CA/MX and the NWPP & RMRG have potential for high load-loss hours and energy shortfalls for 2022 and beyond. In updated probabilistic studies of demand and resource scenarios for 2022, WECC-CA/MX shows 10 potential hours of load loss, and the NWPP-US & RMRG area shows 23. Higher load-loss metrics were seen in the 2024 study year for all U.S. areas of the WI.

In addition, the planned retirement of the 2,200 MW Diablo Canyon Power Plant generating stations in 2024 and 2025 contributes to a projected capacity shortfall in WECC-CA/MX beginning in 2026. Reserve margins in WECC-CA/MX are also declining because of the energy limitations of solar PV resources at the peak demand hour, which occurs later in the day when solar PV resource output is lower.

As the probabilistic assessment reflects, when assessing the WECC sub-regions with non-expected levels of demand and resource availability, maintaining reliability to a 1-day-in-10-year threshold of reliability for every hour is not achieved. One 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.

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

[13] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

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.

According to 2021 LTRA, parts of North America are exposed to energy shortfall risks in the near-term assessment period from wide-area and long duration extreme weather events like the 2020/2021 western heat wave and winter storm Uri in 2021. Details include the following:

- Extreme weather can cause challenging grid operating conditions by both diminishing the supply of electricity and driving actual demand above forecasts. Near-term demand forecasts, resource projections, and other trends suggest that even parts of North America that are considered resource adequate at the traditional peak hour evaluation are becoming increasingly exposed to energy shortfall risks in extreme weather events.

- The increasing volatility and uncertainty of electricity demand makes accurate load forecasting a challenge, increasing the risk that Balancing Authorities ("BA") may be unprepared for the peak demands that can accompany extreme weather events. In extreme temperatures, areas with relatively high seasonal load forecast uncertainty ("LFU") and low PRM are at risk of capacity shortfall: WECC-CA/MX and NWPP-US & RMRG areas near-term summer projections fall into this category.

Most areas are projecting to have adequate resource capacity to meet annual peak demand associated with normal weather. Capacity shortfalls, where they are projected, are the result of future generator retirements that have yet to be replaced with new resource capacity. Capacity-based estimates, however, can give a false indication of resource adequacy. Energy risks emerge when variable energy resources like wind and solar are not supported by flexible resources that include sufficient dispatchable, fuel-assured, and weatherized generation.

The Companies' BAA is included in the NWPP 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 addition of variable energy resources, primarily wind and solar, and the retirement of conventional generation is fundamentally changing how the bulk power systems ("BPS") are planned and operated.

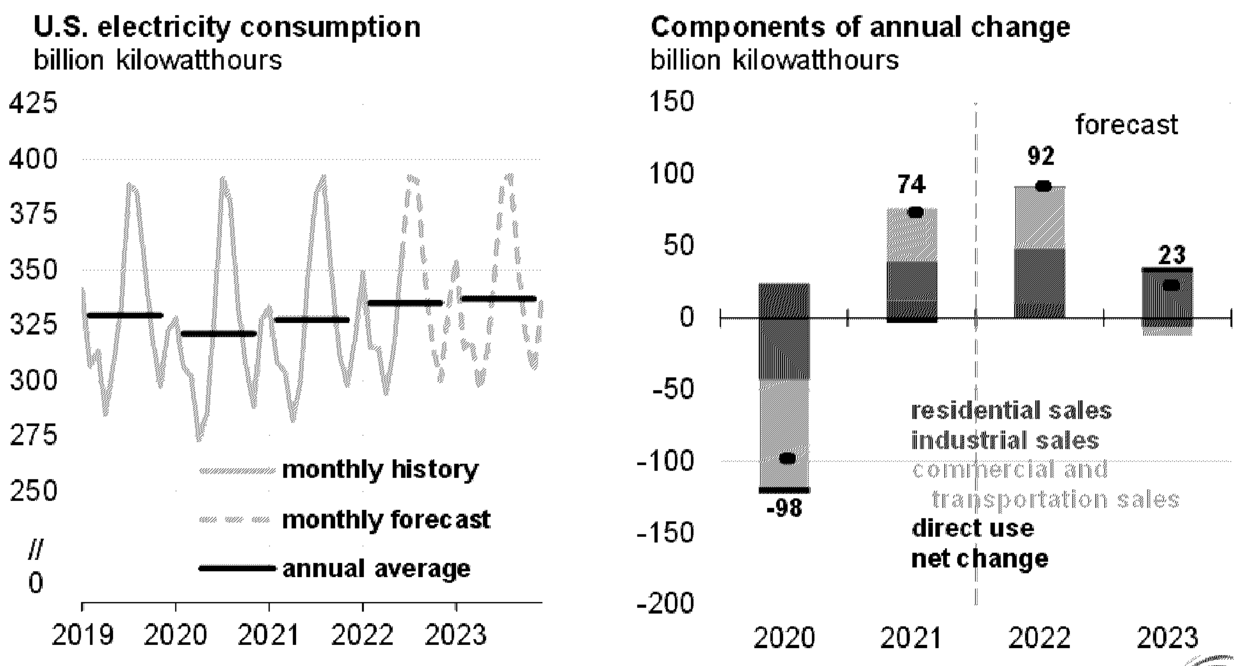
As further discussed in section C.6, The Companies have some concerns regarding the ability to obtain sufficient energy to fill any additional open positions that may occur during the ESP forecast period due to the increased market uncertainty discussed above.

3. ELECTRICITY

Electricity consumption. Electricity sales to customers in the commercial and industrial sectors are growing faster than sales to the residential sector. Commercial electricity use is related both to overall weather patterns and economic trends. The United States Energy Information Administration ("EIA") estimates that 5 percent more electricity was used by the commercial sector in 1H22 than 1H21. Stronger economic activity than in 2021 drove most of this growth. Nonfarm employment in 1H22 grew by 5 percent year over year. EIA expects economic growth to slow somewhat in 2H22, but still expects commercial electricity use to rise by 3 percent in 2022. The slower economic growth contributes to the forecast that electricity consumption in the commercial sector will remain relatively unchanged next year.

The total consumption of electricity in the United States, including sales to ultimate customers and direct use of electricity by generators, is forecasted to increase by 2 percent in 2022 and by 1 percent in 2023. Sales of electricity to ultimate customers account for about 97 percent of total U.S. electricity consumption.

FIGURE ESP-23
ELECTRICITY CONSUMPTION

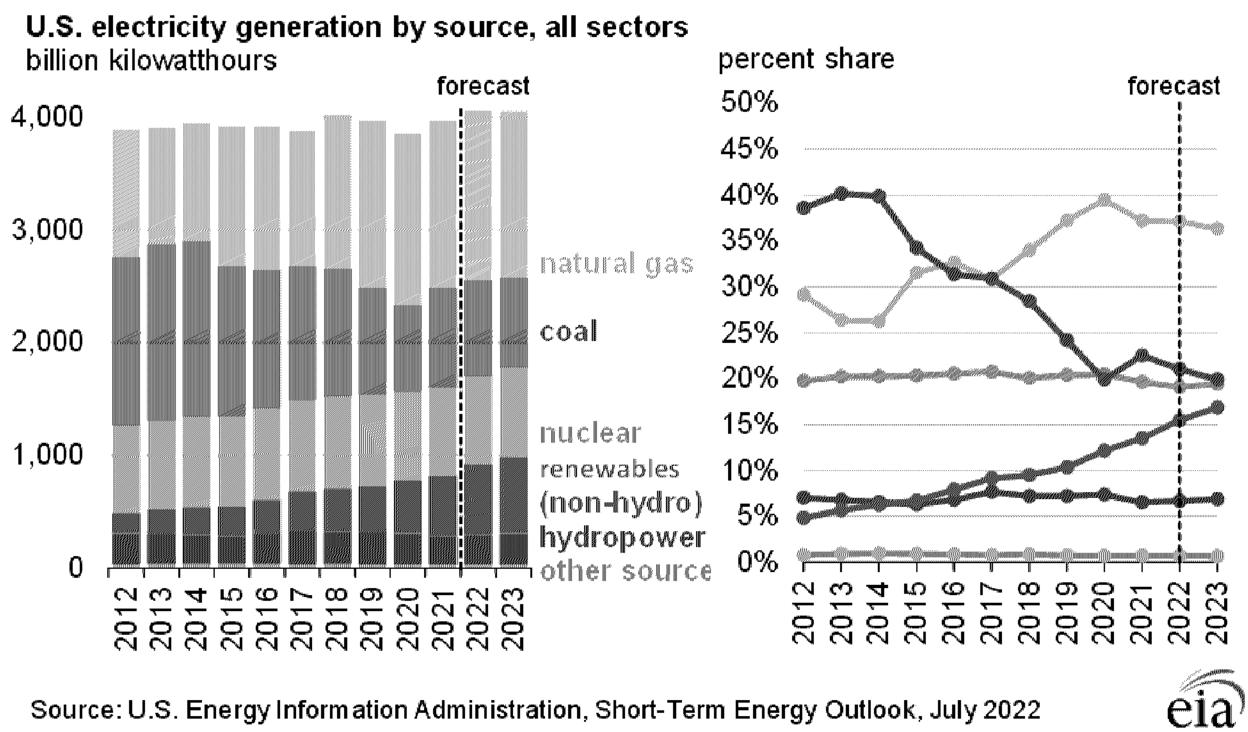


Source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2022

During 2H22, EIA expects U.S. residential electricity consumption to be similar to 2H21. Sales of electricity to residential customers are forecasted to grow by 1 percent for all of 2022 and then fall slightly in 2023 as winter and summer temperatures return to more normal levels. The U.S. industrial production index for electricity-intensive industries increased year over year by 5 percent in 1H22, and EIA expect it to grow at a similar rate in 2H22. As a result, 4 percent more sales of electricity is expected to the industrial sector in 2022 than in 2021. Forecast of industrial electricity use grows slightly less at 3 percent in 2023, reflecting slower overall economic growth.

Electricity generation. EIA estimates that electricity generation by the electric power sector during the first half of 2022 grew 4 percent from 1H21, reflecting warmer-than-normal temperatures in May and June. Expectation is that U.S. electric power sector will generate 4,055 billion kilowatt-hours ("BkWh") in 2022, which is a 2 percent increase from 2021. Forecast electric power sector generation remains at about the same level in 2023. EIA also forecasts that most of the increase in U.S. electricity generation through 2023 will come from renewable energy sources as a result of growth in renewable generating capacity. Renewable energy is forecasted to provide 22 percent of electric power sector generation in 2022 and 24 percent in 2023, compared with 20 percent in 2021.

FIGURE ESP-24
ELECTRICITY GENERATION BY SOURCE



Renewable energy. Most of the EIA forecast increase in generation from renewables comes from solar capacity expansions in the electric power sector. Solar electricity generation is expected to increase to 145 BkWh in 2022 and 182 BkWh in 2023. Installed capacity of solar PV generation continued to grow despite supply chain and commerce issues that affected the industry during the past six months. EIA forecasts that the electric power sector will add 19 gigawatts ("GW") of solar capacity in 2022 and an additional 23 GW in 2023.

In February, U.S. tariffs on imported crystalline silicon solar products from China were extended, setting an annual tariff-rate quota for solar cells imported from China to 5 GW, with exemption of bifacial panels. In March, the U.S. Department of Commerce ("DOC") announced an anti-dumping circumvention investigation of solar cells and modules imported from Cambodia, Malaysia, Thailand, and Vietnam—countries that allegedly use parts made in China that otherwise would be subject to tariffs. DOC is expected to make a decision by the first quarter of 2023. In June, by Executive Order, the President invoked the Defense Production Act to ease import duties for a 24-month period for solar cells and modules imported from Cambodia, Malaysia, Thailand, and Vietnam. EIA preliminary data from January to April 2022 indicate that an average of 3.9 GW of PV solar installations reported delays compared with 2.1 GW delayed during the same period last year.

We can expect continued growth in solar energy through 2023, in part because of the solar investment tax credit under the Consolidated Appropriations Act, which offers a 26 percent tax credit to projects that start in 2022. The credit drops to 22 percent for projects that start in 2023. States such as Texas and Florida are set to add significant solar PV in the next two years.

EIA forecasts that electricity generation from wind will increase by 16 percent in 2022 from 2021 and by 4 percent in 2023 from 2022. Wind capacity in the electric power sector will grow by 11 GW in 2022 and by an additional 4 GW in 2023, down from the 14 GW added yearly in 2021 and 2020. We can attribute slower growth in wind capacity, in part, to the phasedown of the production tax credit ("PTC") as well as supply chain issues. The PTC, which was extended through the 2022 calendar year, provides a 2.6 cent per kWh benefit for facilities entering service or spending at least 5 percent of total estimated project cost (securing 5 percent safe harboring). Producers of safe harbored projects are able to claim the PTC four years after they qualify.

Hydropower contributed 7 percent of electric power generation in 2021. In the forecast, the share of hydropower generation will remain around 7 percent in both 2022 and 2023. Since 2021, the drought affecting the West has constrained electricity generation by hydropower, and California is one of the most affected states.

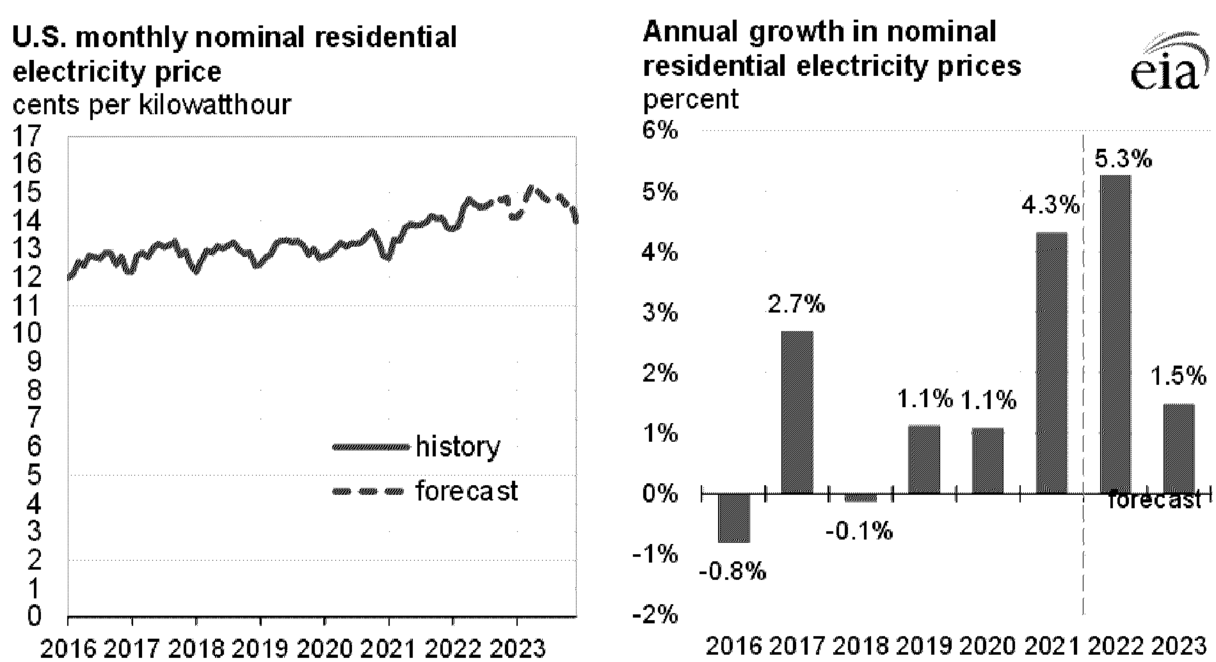
Economic factors, such as fuel costs and changes in the mix of generating capacity, are likely to affect trends in electricity generation from nonrenewable sources. The price of natural gas, in particular, has traditionally been an important driver of the relative use of natural gas and coal for power generation. Natural gas prices have significantly increased from last year, and are expected to remain high through the end of 2022.

In the past, high natural gas prices have typically led to more generation from coal-fired power plants. However, the industry continues to retire coal-fired generation capacity. According to the latest information from the Form EIA-860 survey, the United States will have 10 percent, or nearly 22 GW, less operating coal capacity at the end of 2023 than at the end of 2021. In addition to these capacity retirements, coal-fired power plants have not received sufficient fuel deliveries because of limited rail capacity and reduced coal mine capacity. In some regions of the country, such as the Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") power markets, increased growth in renewables contributes to the forecast decline in coal-fired electricity generation. EIA expects that coal's share of U.S. total generation will fall from 23 percent in 2021 to 21 percent this year and 20 percent in 2023.

The constraints on coal-fired electricity generation are resulting in more natural gas-fired generation, despite the high fuel costs. Expectation is that natural gas's share of total U.S. generation to average about 37 percent in 2022, similar to the generation share in 2021, and 36 percent 2023. Despite higher prices for natural gas, some regions, particularly in the mid-Atlantic and Southeast, will increase natural gas-fired electricity generation this year. The recent coal-fired power plant retirements and the constraints on coal deliveries are affecting these regions the most.

Electricity prices. The large increase in natural gas fuel costs over the past year is also driving up wholesale electricity prices throughout the United States. Increases in wholesale prices during the first half of 2022 ranged from 13 percent higher than first half 2021 in the Southwest region to 135 percent higher in the New York ISO region. Average year-to-date prices are lower in the Central/SPP and Texas/ERCOT regions because of extreme price spikes that occurred in February 2021. EIA expects wholesale electricity prices to remain elevated through the remainder of 2022. Forecast for a decline in natural gas prices next year contributes to forecast that electricity prices will fall in all regions in 2023.

FIGURE ESP-25
U.S. ELECTRICITY PRICES



Source: U.S. Energy Information Administration, Short-Term Energy Outlook, July 2022

4. 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 Western Canadian Sedimentary Basin in Alberta and British Columbia, Canada. The Companies also access natural gas supplies from the Rockies region, principally the states of Wyoming, Colorado, and Utah.

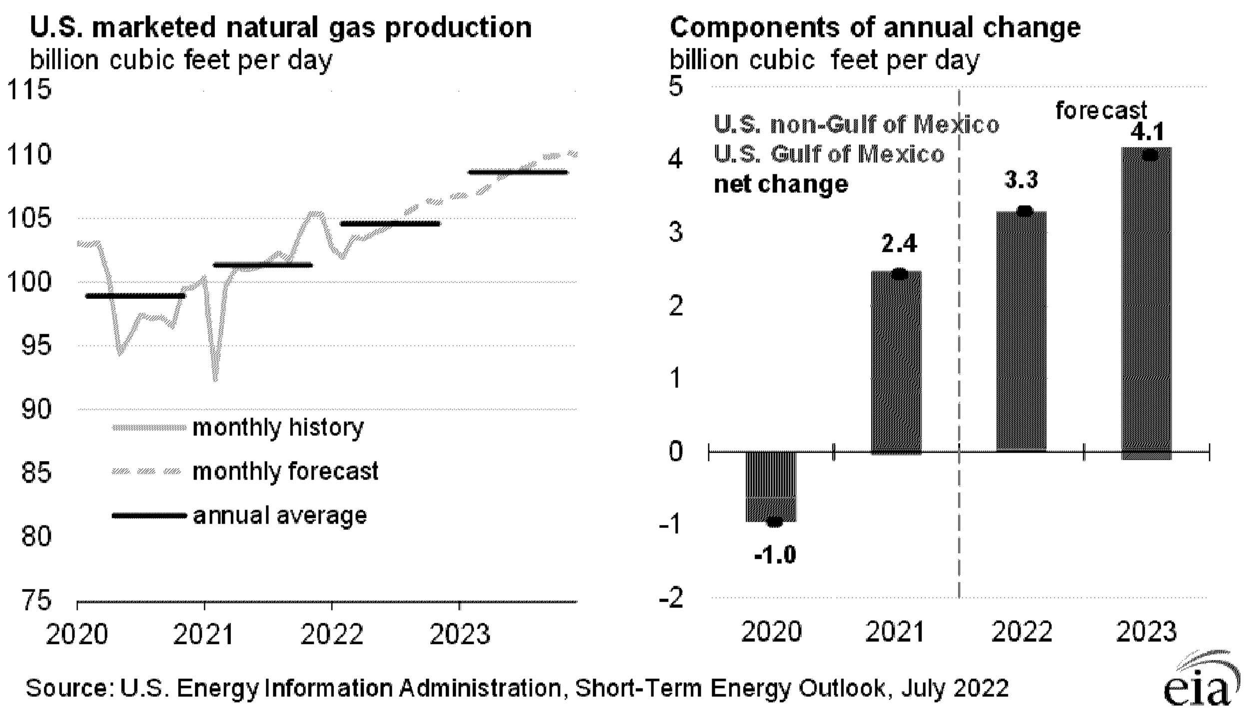
Natural gas consumption. EIA expects U.S. natural gas consumption will increase by 2.9 billion cubic feet per day (Bcf/d) (3 percent) to average 85.9 Bcf/d in 2022 and fall to 85.4 Bcf/d in 2023. Consumption of natural gas is expected to increase in all sectors in 2022, with the largest increase in the electric power sector. Electric power sector will consume an average of 31.9 Bcf/d of natural gas in 2022, which is 3 percent more than in 2021. EIA's forecast increase occurs despite high natural gas prices in 2022, which in the past have typically encouraged more switching from natural gas to coal as an electricity generation source. The electric power sector continues to use high amounts of natural gas because coal-fired power plants are limited in their ability to act as an alternative source of electricity generation. Ongoing coal capacity retirements, limited rail capacity for fuel delivery to coal plants, and lower-than-average stocks at coal plants have all contributed to reduced coal-fired electricity generation. As a result, more natural gas has been used to meet electricity demand. Consumption of natural gas in the electric power sector is expected to decline slightly by 0.5 Bcf/d (1 percent less) in 2023 as more electric-generation capacity from renewable energy sources comes online.

Consumption of natural gas in the industrial sector in the EIA forecast increases by 3 percent this year, averaging 23.2 Bcf/d in 2022, as demand for industrial goods and economic activity increases. Industrial sector consumption of natural gas will be mostly unchanged in 2023 compared with 2022.

EIA expects combined residential and commercial natural gas consumption to average 22.6 Bcf/d in 2022 and 22.4 Bcf/d in 2023, based largely on weather expectations derived from National Oceanic and Atmospheric Administration ("NOAA") forecasts. The most recently published EIA short term outlook assumes colder temperatures in 2022 than in 2021 and similar temperatures in 2023.

Natural gas production. EIA forecasts that dry natural gas production will average 96.2 Bcf/d in 2022 in the United States, an increase of 2.7 Bcf/d (3 percent) compared with 2021. Increases in crude oil and domestic natural gas prices, as well as increases in the number of active oil and natural gas rigs, will contribute to an overall increase in drilling activity in 2022 and 2023 that will lead to production growth. In 2023, dry natural gas production is expected to increase by 3.7 Bcf/d (4 percent) to reach 100.0 Bcf/d. The Haynesville region and the Permian Basin will drive growth in dry natural gas production, supported by increased pipeline takeaway capacity in both regions and high oil production in the Permian Basin that results in greater levels of associated natural gas production.

FIGURE ESP-26
U.S. NATURAL GAS PRODUCTION



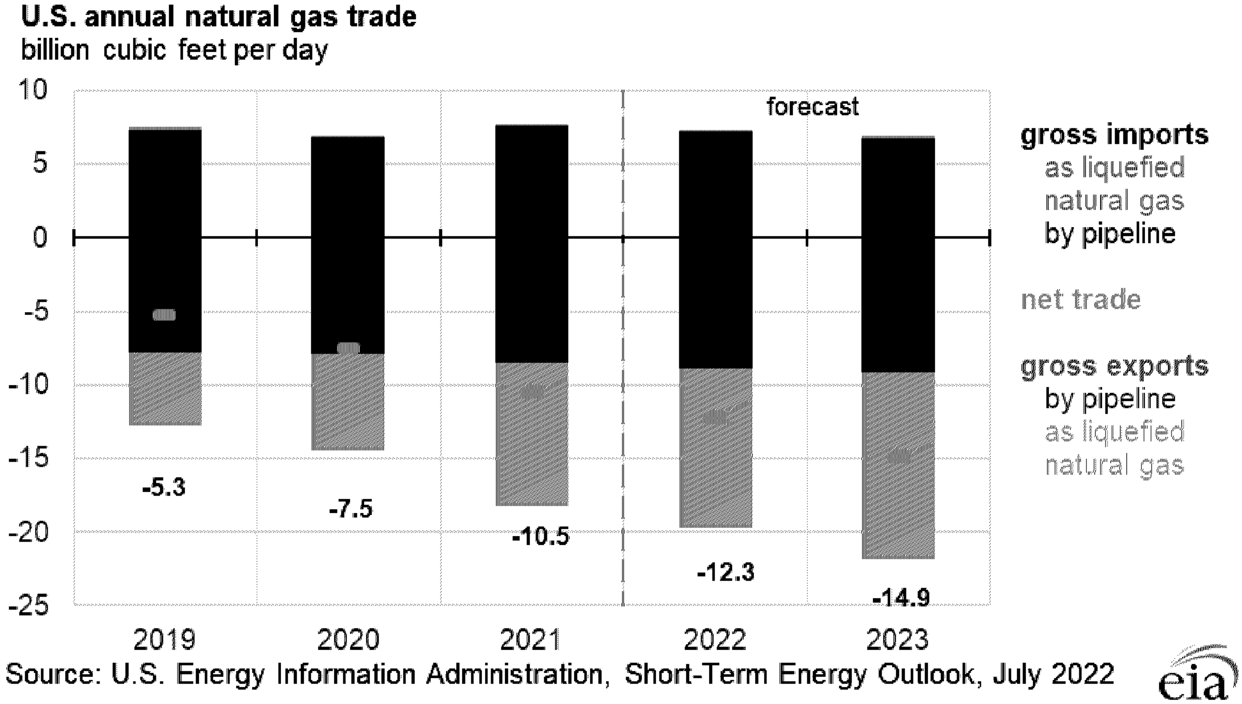
Natural gas trade. Liquefied natural gas ("LNG") exports continued to drive growth in U.S. natural gas exports in the first half of 2022 (1H22). LNG exports averaged 11.2 Bcf/d during 1H22 and set a monthly record in March 2022, averaging 11.7 Bcf/d. U.S. LNG export capacity is continuing to expand this year with the addition of the Calcasieu Pass LNG export facility, which has been ramping up LNG production ahead of schedule and is expected to be fully operational by the third quarter of 2022 ("3Q22"). Strong natural gas demand and high LNG prices in Europe and Asia drove the continued growth in LNG exports in the first half of this year. During the first five months of 2022, the United States exported 71 percent of its LNG to Europe, compared with an annual average of 34 percent last year. In the past, Asia had been the main destination for U.S. LNG exports, accounting for almost half of the total exports in 2020 and 2021. LNG prices in Europe remain high amid supply uncertainties because of Russia's invasion of Ukraine and the need to replenish Europe's natural gas inventories, which has kept Europe's demand for LNG elevated.

Since December 2021, the European Union ("EU") and the United Kingdom have been importing record volumes of LNG, primarily to fill natural gas storage inventories, which were historically low from fall 2021 through spring 2022. The United States became the largest LNG supplier to the EU and United Kingdom last year, accounting for 26 percent of total imports. In the first five months of 2022, LNG imports from the United States to the EU and the United Kingdom continued to grow.

For the second half of this year, U.S. LNG exports will decline because of the outage at the Freeport LNG export facility, which is not expected to return to full service until late 2022. The shutdown of Freeport LNG will reduce U.S. LNG export capacity by approximately 2 Bcf/d, which is about 17 percent of the total capacity. EIA forecasts U.S. LNG exports to average 10.5 Bcf/d in 2H22, and will continue to grow in 2023, averaging 12.7 Bcf/d on an annual basis, 17 percent higher than in 2022.

U.S. exports of natural gas by pipeline, almost all of which move natural gas to Mexico, average 8.8 Bcf/d in 2022 in the forecast, up 4 percent from 2021, and then rise by an additional 4 percent to reach 9.2 Bcf/d in 2023. Figure ESP-27 illustrates U.S. annual exports and imports.

FIGURE ESP-27
U.S. NATURAL GAS TRADE



Natural gas prices. The Henry Hub spot price averaged $6.07 per million British thermal units ("MMBtu") in 1H22, rising steadily from an average of $4.38/MMBtu in January to $8.14/MMBtu in May. Prices then fell in June, in part, because of the outage at the Freeport LNG export terminal. The increase through May resulted from continued demand for LNG exports, increased demand in electric power generation as a result of limited natural gas-to-coal switching, and decreased production compared with the end of 2021.

Natural gas prices have been volatile in 2022. The 30-day historical volatility of U.S. natural gas prices averaged 179.1 percent in February compared with the five-year average of 47.7 percent. Historical volatility measures the magnitude of daily changes in the closing price for a commodity during a specific time in the past. Natural gas price volatility resulted, in large part, from the uncertainty in the global natural gas markets leading up to and following Russia's invasion of Ukraine on February 24, as well as from weather-related fluctuations in natural gas demand. Uncertainty around production that was relatively flat in 1H22 (and slightly lower than the high levels reached at the end of 2021) has also contributed to price volatility. Natural gas price volatility remained relatively high in 2Q22, averaging 87.2 percent in June.

According to EIA's July 2022 forecast, the Henry Hub spot price will average $5.97/MMBtu in 2H22. This price is down from forecast of $8.58/MMBtu in the June short term energy outlook in part because of the Freeport LNG facility being offline through late 2022, and more natural gas being expected to be injected into storage in 2H22. However, because of ongoing constraints in the coal market that are limiting the use of coal in the electric power sector, electric power-sector use of natural gas will remain strong, keeping upward pressure on prices, particularly in the case of a significant heat wave. Despite the outage at Freeport LNG, full utilization at remaining LNG facilities is expected to raise natural gas prices as Europe's demand for LNG from the United States remains high. EIA expects the Henry Hub spot price will average $4.76/MMBtu for all of 2023.

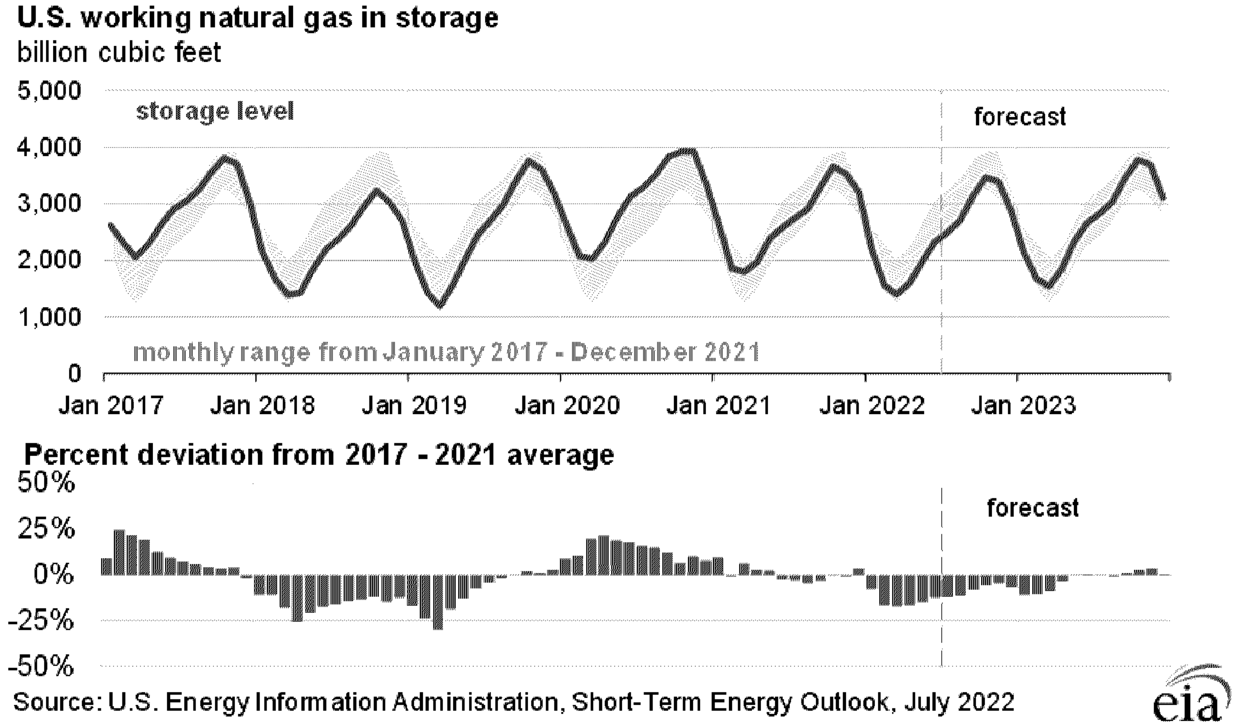
Storage. Natural gas can be stored in underground facilities to be consumed at a later date. Storage is primarily used to meet seasonal load variations, but also can be used as backup for events affecting production or delivery of natural gas (e.g., hurricanes, disruption of production/distribution systems, etc.). Natural gas is injected into storage during periods of low demand and withdrawn during periods of peak demand. Rarely is storage utilized to reduce price volatility. Generally speaking, market participants watch the change in natural gas inventories to gauge supply and demand dynamics, with large inventory builds representing weak demand/strong supply and large inventory draws representing strong demand/weak supply.

U.S. storage withdrawals in 1Q22 were 27 percent higher than the five-year average because of colder-than-normal temperatures that led to higher consumption in the residential, commercial, and electric power sectors and because of declines in natural gas production as a result of weather-related freeze-offs in producing regions. Working natural gas inventories ended March 2022 at 1,401 Bcf, which was 17 percent less than the five-year average for that time of year and the least natural gas held in U.S. underground storage at the end of March (the traditional end of the heating season) since 2019.

As the Freeport LNG outage returns about 2 Bcf/d of natural gas to the domestic market, it is expected that end-of-October storage will be closer the five-year average. EIA expects that inventories will reach 3,468 Bcf at the end of October 2022, which would be 6 percent less than the five-year average for October and 5 percent less than the natural gas in U.S. storage at the end of October 2021.[14] Working gas storage levels for the United States in 2017-2021 and so far in 2022 with the 2023 forecast are shown in Figure ESP-28.

[14] U.S. EIA, "Short-term Outlook" (July 2022).

FIGURE ESP-28
U.S. NATURAL GAS STORAGE



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 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 five 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 the Northwest Pipeline Company at Sumas, Washington, are used to move natural gas in either direction to storage, depending on marketing conditions.

5. COAL

Increased economic activity following COVID-19 shutdowns and rising natural gas prices relative to coal prices led to increased demand for coal-fired power generation in 2021 compared with 2020. Although natural gas prices have remained high in 2022, constraints on coal production from decreased mine capacity and transportation from labor shortages in the railroad industry have led to coal generators taking steps to conserve coal stocks to meet peak electricity demand during the summer, which is limiting coal-fired electricity generation. North Valmy Station's recent coal supply area is spread between Utah and Colorado within the Uinta Basin Coal production.

Coal trade. EIA[15] expects U.S. coal exports to increase 3 percent to 88 million short tons ("MMst") in 2022 from 85 MMst in 2021. It is unclear how much of the U.S. increase in coal exports have been a result of the improved post-pandemic economy and high natural gas prices or a result of sanctions against Russian coal. Increased exports are driven by a forecast 2 percent increase in metallurgical coal exports in 2022 to accommodate increased steel production and an even larger 4 percent increase in steam coal exports as countries increase coal-fired electricity generation relative to natural gas-fired generation to manage costs associated with high natural gas prices. Exports in the forecast fall to 83 MMst in 2023, less than in 2021, as the economy cools down. While metallurgical coal exports remain steady, steam coal exports to are expected to fall 12 percent in 2023 as natural gas prices fall, increasing natural gas-fired generation relative to coal-fired generation.

Coal production. U.S. coal production totaled 289 MMst in the first half of 2022 (1H22), up 6 MMst (2 percent) from 1H21. As coal consumption decreased, increases in production have kept inventories in 1H22 from falling by as much as they did in 1H21. In 2022, EIA expects U.S. coal production to rise by 17 MMst (3 percent) from 2021 to 595 MMst. According to EIA forecast 2022 coal production increases by 15 MMst (5 percent) in the Western Region and by 1 MMst (1 percent) in both the Appalachia and Interior regions. Also, expectation is that U.S. coal production will remain flat in 2023.

Expectation of increased production in 2022 primarily reflects demand to replenish depleted coal stocks. Electric power sector inventories fell significantly in 2021. More draws are expected through summer 2022. In July 2022, EIA forecast that 2022 end-of-year electric power sector coal inventories will decline to 77 MMst, 18 percent less than at the end of 2021. In 2023, coal production is expected to total 594 MMst, about the same as 2022. Much of the decrease in coal mine capacity that has occurred since 2020 appears to be permanent. Coal producers have experienced labor and capital shortages, which is expected to continue to limit coal supply in the forecast.

Coal consumption. In EIA's July forecast, U.S. coal consumption declines to 527 MMst (3 percent) in 2022 and to 506 MMst (4 percent) in 2023, compared with 546 MMst in 2021. EIA expects the retirement of approximately 22 GW of coal-fired power plant capacity through 2023,

[15] U.S. EIA, "Short-term Outlook" (July 2022).

down 10 percent from 2021. As a result, electric power sector demand for coal will decrease by 20 MMst (4 percent) in 2022. Coal plant retirements and lower expected natural gas prices drive an additional 23 MMst (5 percent) decline in 2023.

B. 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"), WoodMac, and the EIA.

The forecasts of natural gas and power prices were prepared by the Companies from near-term market quotes. The methodology to prepare the curve of market quotes is based on an average of prices over the twenty-day trading period from April 1, 2022, through April 30, 2022.

1. NATURAL GAS PRICE FORECAST

Natural gas prices in near-term forward periods can change rapidly in response to current market conditions. For the 2022 ESP gas price forecast, an average of forward prices over 20 trading days in April 2022 was used to develop the base case price projections in the near-term years. High and low price cases were also prepared, using market quotes for implied volatility of gas prices. The scenarios serve to capture a potential range of price outcomes.

The natural gas price forecast focuses on monthly projections for the Henry Hub and, for dispatching purposes, the SoCal and Malin trading hubs. The natural gas price forecast for 2023-2024 was prepared utilizing pure market quotes from the Argus trading settlements for Henry Hub plus western regional basis quotes.[16] The ESP natural gas price forecast utilizes pure quotes through March 2025 and a blend of quotes with long-term fundamentals for the period from April 2025 through March 2027.

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). High- and low-power price forecasts were prepared to reflect Western energy prices that fluctuate with the respective natural gas price forecasts, using the heat rate of a typical combined-cycle unit. The profit margin (or spark spread) reflected in the base case price forecast was added to both the higher and lower computed energy prices. The spark spread is calculated as a dollar per megawatt-hour value. Figures ESP-29 and ESP-30 depict the resulting base, high, and low monthly prices for the SoCal and Malin hubs used in this ESP Update.

[16] The prices at western delivery hubs are commonly quoted as a basis to the Henry Hub.

FIGURE ESP-29
NATURAL GAS PRICE FORECAST (SOCAL)

[redacted]

FIGURE ESP-30
NATURAL GAS PRICE FORECAST (MALIN)

[redacted]

2. POWER PRICE FORECAST

Prices for western wholesale power markets are forecasted monthly for both on-peak and off-peak periods.[17] The power price forecast is almost exclusively based on prices at Mead hub. The Mead prices are based on an average of market closing prices for April 2022 or the same trading period used in determining the natural gas price forecast.

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 heat rate of a high-efficiency combined cycle generator. The product of this calculation is added to the monthly on-peak spark spreads

[17] 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.

from the base case price forecast to compute the high and low energy prices. Figure ESP-31 shows the forecast of average power prices for 2023-2024.

FIGURE ESP-31
POWER PRICE FORECAST (MEAD -AVERAGE)

[redacted]

3. COAL PRICE FORECAST

Coal price forecast utilizes market forecasts produced by S&P Global Market Intelligence for the coal producing basins that supply Valmy Station. Coal locations and qualities included in their forecast are labeled based on location, transportation type, heat content and SO_2 rate. S&P Global Market Intelligence describes their longer-term forecast methodology as driven by fundamental estimates of cash costs of production, accepted returns to capital, regional productive capacity, and forecast supply and demand. In addition, results from the Companies' recent coal market solicitations are considered. Rail rates are projected using Sierra's existing Union Pacific contract and likely future trends in rail transportation rates. Figure ESP-32, a confidential table, provides the projected coal prices for Valmy.

FIGURE ESP-32
PROJECTED COAL PRICES

[redacted]

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, agreements for purchase of PCs, and energy efficiency programs. The Companies also sell portfolio credits under the NGR program.

Figures ESP-33A and ESP-33B list all of the Companies' renewable and non-renewable PPAs, and sales agreements.

FIGURE ESP-33A
NEVADA POWER LONG-TERM PPAs

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date
Renewable Purchase Agreements				
PPAs (Commercial)				
ACE Searchlight[QF]	Solar[S]	17.5	12/16/2014	12/31/2034
APEX Landfill[QF]	Methane	12.0	3/1/2012	12/31/2032
Boulder Solar I[EWG]	Solar[S]	100.0	12/9/2016	12/31/2036
Colorado River Commission-Hoover	Hydro	237.6	10/1/2017	9/30/2067
Copper Mountain 5[EWG]	Solar[S]	250.0	7/23/2021	12/31/2046
Desert Peak 2[QF]	Geothermal	25.0	4/17/2007	12/31/2027
FRV Spectrum[QF]	Solar[S]	30.0	9/23/2013	12/31/2038
Jersey Valley[QF]	Geothermal	22.5	8/30/2011	12/31/2031
McGinness Hills[QF]	Geothermal	96.0	6/20/2012	12/31/2032
Mountain View[EWG]	Solar[S]	20.0	1/5/2014	12/31/2039
Nevada Solar One (NPC)[QF]	Solar[T,X]	46.9	6/27/2007	12/31/2027
NGP Blue Mountain[QF]	Geothermal	49.5	11/20/2009	12/31/2029
RV Apex[QF]	Solar[S]	20.0	7/21/2012	12/31/2037
Salt Wells[QF]	Geothermal	23.6	9/18/2009	12/31/2029
Silver State[EWG]	Solar[F]	52.0	4/25/2012	12/31/2037
Spring Valley[EWG]	Wind	151.8	8/16/2012	12/31/2032
Stillwater Geothermal[1,QF]	Geothermal	47.2	10/10/2009	12/31/2029
Stillwater PV[1,QF]	Solar[F]	22.0	3/5/2012	12/31/2029
Switch Station 1[EWG]	Solar[S]	100.0	8/8/2017	12/31/2037
Switch Station 2 (NPC)[EWG]	Solar[S]	0.0	10/11/2017	12/31/2037
Techren I[EWG]	Solar[S]	100.0	3/11/2019	12/31/2044
Techren III[QF]	Solar[S]	25.0	10/7/2020	12/31/2045
Techren V[EWG]	Solar[S]	50.0	12/31/2020	12/31/2045
Tuscarora[QF]	Geothermal	32.0	1/11/2012	12/31/2032
WM Renewable Energy-Lockwood[QF]	Methane	3.2	4/1/2012	12/31/2032
		1533.8		
PC Purchase Agreements				
NPC-SPPC	Geothermal	2.3	10/30/2009	12/31/2028
Nellis I (Solar Star)[QF]	Solar	13.2	12/15/2007	12/31/2027
SunPower (LVVWD)	Solar	3.0	4/20/2006	12/31/2026
		18.5		
PPAs (Pre-Commercial)[2]				
Eagle Shadow Mountain[EWG]	Solar[S]	300.0	3/1/2023	12/31/2048
Moapa (Arrow Canyon) Solar[EWG]	Solar[S,X=75 (5 hrs)]	200.0	12/1/2022	12/31/2047
Southern Bighorn Solar[EWG]	Solar[S,X=135 (4 hrs)]	300.0	9/1/2023	12/31/2048
Chuckwalla[EWG]	Solar[S,X=180 (4 hrs)]	200.0	12/1/2023	12/31/2045
Boulder Solar III[EWG]	Solar[S,X=58 (4 hrs)]	128.0	12/31/2023	12/31/2035
Gemini Solar[EWG]	Solar[S,X=380 (3.7 hrs)]	690.0	5/1/2024	12/31/2049
		1818.0		
Non-Renewable Purchase Agreements				
Nevada Cogeneration Associates #1[QF]	Natural Gas	85.0	6/18/1992	4/30/2023
Nevada Cogeneration Associates #2[QF]	Natural Gas	85.0	2/1/1993	9/30/2023
Saguaro Power Company[QF]	Natural Gas	90.0	10/17/1991	9/30/2022
		260.0		
Renewable and Non-Renewable Sales				
Switch NGR (Switch Station 1)	NGR Agreement (Sale of PCs)	100.0	8/8/2017	12/31/2037
Switch NGR-NPC (Switch Station 2)	NGR Agreement (Sale of PCs)	0.0	10/11/2017	12/31/2037

Notes:

1. The geothermal and solar facilities are combined into one PPA.

2. Facilities are either under development or construction (the dates shown are expected dates).

QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage

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

FIGURE ESP-33B
SIERRA LONG-TERM PPAs

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date
Renewable Energy				
PPAs (Commercial)				
Battle Mountain[EWG]	Solar[S, X=25MW (4 hrs)]	101.0	6/23/2021	12/31/2046
Beowawe[QF]	Geothermal	17.7	4/21/2006	12/31/2024
Boulder Solar II[EWG]	Solar[S]	50.0	1/27/2017	12/31/2037
Brady[QF]	Geothermal	24.0	7/30/1992	7/31/2022
Burdette[QF]	Geothermal	26.0	2/28/2006	12/31/2026
Dodge Flat[EWG]	Solar[S, X=50MW (4 hrs)]	200.0	3/2/2022	12/31/2047
Fish Springs Ranch[EWG]	Solar[S, X=25MW (4 hrs)]	100.0	3/15/2022	12/31/2047
Galena 3[QF]	Geothermal	26.5	2/21/2008	12/31/2028
Hooper[1, QF]	Hydro	0.75	6/23/2016	12/31/2040
Kingston[1]	Hydro	0.175	9/19/2011	12/31/2040
Mill Creek[1]	Hydro	0.037	9/1/2011	12/31/2040
Nevada Solar One (SPPC)[QF]	Solar[T,X]	22.1	6/27/2007	12/31/2027
RO Ranch[1,2]	Hydro	0	3/15/2011	12/31/2040
Rye Patch[1]	Hydro	0.75	5/2/2019	12/31/2040
Steamboat 2[QF]	Geothermal	13.4	12/13/1992	12/12/2022
Steamboat 3[QF]	Geothermal	13.4	12/19/1992	12/18/2022
Switch Station 2 (SPPC)[EWG]	Solar[S]	79.0	10/11/2017	12/31/2037
Techren II[EWG]	Solar[S]	200.0	10/4/2019	12/31/2044
Techren IV[QF]	Solar[S]	25.0	10/7/2020	12/31/2045
Turquoise[EWG]	Solar[F]	50.0	12/4/2020	12/31/2045
TCID New Lahontan[QF]	Hydro	4.0	6/12/1989	6/30/2025
TMWA Fleish	Hydro	2.4	5/16/2008	6/1/2028
TMWA Verdi	Hydro	2.4	5/15/2009	6/1/2029
TMWA Washoe	Hydro	2.5	7/25/2008	6/1/2028
USG San Emidio[QF]	Geothermal	11.75	5/25/2012	12/31/2037
		972.9		
PC Purchase Agreement				
TMWRF	Methane	0.8	9/9/2005	12/12/2024
PPAs (Pre-Commercial)[3]				
North Valley	Geothermal	25	12/31/2022	12/31/2047
Non-Renewable Purchase Agreements				
Liberty (CalPeco) EBSA	Diesel	12.0	1/1/2011	12/31/2031
		12.0		
Renewable & Non-Renewable Sales Agreements				
Liberty (CalPeco)	Full Requirements (Capacity/Energy/PCs)	See Note 4	12/30/2020	12/29/2025
NPC-SPPC	Sale of PCs (Geothermal)	2.3	10/30/2009	12/31/2028
Truckee Meadows Community College NGR (Techern I)	NGR Agreement (Sale of PCs)	See Note 6	12/1/2019	11/30/2022
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).
6. SPPC shall sell 7,200 kPCs per year for three years after PUCN approval.
7. Soda Lake II was decommissioned by counterpary and awaiting legal options (the PPA is still active).

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 30 long-term renewable PPAs (*see* Nevada Power Figure ESP-34A above) representing a total nameplate capacity of approximately 4,101.8 MW, including 750 MW with 580 MW of storage of company-owned asset but managed as a PPA. The owned projects are Dry Lake Solar project (150 MW with 100 MW of storage), Iron Point Solar project (250 MW with 200 MW of storage) and Hot Pot Solar Project (350 MW with 280 MW of storage), and are assumed to achieve commercial CODs in December 2023, December 2023 and December 2024 respectively. The pre-commercial Moapa (Arrow Canyon) project (200 MW) and the Eagle Shadow Mountain project (300 MW) are expected to achieve their contractual CODs in 1st quarter of 2023. In addition, the Southern Bighorn Solar project (300 MW with 135 MW of storage), and Gemini Solar project (690 MW with 380 MW of storage) are assumed to achieve their contractual CODs in September 2023 and December 2024, respectively. The Chuckwalla Solar project (200 MW with 180 MW of storage) and Boulder Solar III project (128 MW with 58 MW of storage) are assumed to achieve their contractual commercial operation dates in December 2023.

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 26 long-term renewable PPAs representing a total nameplate capacity of approximately 997.9 MW (*see* Sierra Figure ESP-34B above). The latest commercial additions to the portfolio are the Dodge Flat project (200 MW with 50 MW of storage) and Fish Springs Ranch project (100 MW with 25 MW of storage), which both achieved commercial operation in March 2022.

The pre-commercial North Valley project (25 MW) is expected to achieve its contractual commercial operation date in December 2022. 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

Nevada Power has executed three long-term non-renewable PPAs representing a total capacity of approximately 260 MW. The agreements are for the must-take output of the Nevada Cogeneration Associates ("NCA") 1, NCA 2, and Saguaro gas-fueled co-generation qualifying facilities.

Sierra has executed one long-term non-renewable PPA with Liberty Utilities (CalPeco Electric) LLC ("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 six NGR agreements 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,), Truckee Meadows Community College (associated with a portion of the Techren I Solar project output), 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 portfolio credits to Nevada Power. This portfolio credit only sale agreement expires December 31, 2028.

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

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 through broker markets and with approved counterparties 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.

In 2008, the Companies began issuing reverse RFPs to sell forward heat rate call options to the extent that capacity was not expected to be needed to serve load. A copy of the Forward Power Sales Procedures Manual is provided as Technical Appendix POWER-1.

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 bi-lateral contracts to fill their short capacity and energy positions. If an assessment concludes that the Companies are expected to be long, a market survey is conducted in order to identify sales opportunities.

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 hourly 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.

Short-term energy transactions or adjustments to planned 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.

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 or through a reverse RFP process as specified in the Forward Power Sales Procedures Manual (Technical Appendix POWER-1). Forward sales transactions will 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. 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 will 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 close the 2023 summer open position and a portion of the 2024 summer open position in the first and second quarters of 2023.

- The Companies propose to continue the four-season laddering strategy to fill the remaining open positions in 2023 and 2024 and begin filling the 2025 open position.

- In addition to the request for proposal process, the Companies propose to negotiate and transact directly with counterparties in an effort to solicit non-standard firm energy products which may more cost-effectively address the short-term supply challenges during the early evening net demand peak period (i.e., the hours past the gross peak when solar production is very low or zero).

- 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 1,409 MW open capacity position in 2023 and 882 MW open capacity position in 2024. Therefore, the Companies plan to implement a four-season laddering strategy for the procurement of capacity to close the open position. This is similar to the strategy they currently use for the procurement of physical natural gas. Specifically, the Companies plan to close the 2023 summer open position and a portion of the 2024 summer open position in the first and third quarters of 2023 through purchases of energy and/or capacity executed through a competitive procurement process. Thereafter, in the third quarter of 2023, the Companies plan to continue to close the remaining portion of the 2024 and the begin filling 2025 open summer positions using the same four-season laddering strategy, 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-34 below.

The seasons in the four-season laddering strategy refer to the winter and summer seasonal definitions in the natural gas market. This aligns 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.

The procurement schedule for summer 2023 illustrates the full implementation of the four-season laddering strategy. Figure ESP-34 reflect the transaction percentages per season.

FIGURE ESP-34
PERCENTAGE OF REMAINING OPEN POSITION THAT IS CLOSED IN EACH TRANSACTION PERIOD

Incremental transaction	Delivery		
	Summer 2022	Summer 2023	Summer 2024
Q3 2020	25%		
Q1 2021	25%		
Q3 2021	25%	25%	
Q1 2022	25%	25%	
Q3 2022		25%	25%
Q1 2023		25%	25%
Q3 2023			25%
Q1 2024			25%
Sum	100%	100%	100%

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 United States., 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 7,625 MW for the summer of 2023 and 8,354 MW for the summer of 2024. 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 purchased power is directly proportional to the level of secured capacity under each 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 new, higher, 16 percent PRM in the 2021 Joint IRP. The Companies' 16 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, climate change is 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 filings to address the variability of renewable resources and their contribution to resource adequacy by updating the Effective Load Carrying Capability ("ELCC") and PRM to address changes in weather through the use of new trended weather load forecasts, and take first steps regarding concerns about market availability, the concern and focus remains on the uncertain availability and deliverability of market capacity and energy.

While Nevada saw a milder summer in 2022 than 2021, the United States faced record temperatures that highlight the growing risk of extreme weather events. July 2022 was the third-hottest July on record for the U.S. according to scientists from NOAA's National Centers for Environmental Information. Texas reported its hottest summer on record. Portland and Seattle both set new heat duration records in July. As mentioned in the IRP First Amendment, continued drought conditions have led to supply reductions from numerous hydroelectric power plants. Specifically in California and the Desert Southwest Region, water levels remain critically low and continue to drop. One hundred percent of Nevada is in a state of drought with 21.32 percent in the worst level of exceptional drought. In California, 99.79 percent of the state is in a drought with 11.59 percent in exceptional drought. This all leads to the likely scenario that output from major hydroelectric facilities in the West such as Hoover, Glen Canyon and Hyatt will be reduced or eliminated in the near future, adding to the already existing market uncertainty.

NV Energy has experienced extreme weather and weather-related events in recent years. On July 9, 2021, NV Energy experienced an Energy Emergency Alert ("EEA") Level 3 event when a wildfire in southern Oregon resulted in the instantaneous reduction of approximately 5,500 MW of transmission capacity on the two most critical transmission lines flowing power from the Pacific Northwest to the Desert Southwest. The Companies' total curtailment was 1,406 MW[18] and trading staff took every available action to procure replacement supply to maintain resource adequacy. This EEA event occurred on the same day on which Nevada and many other western states experienced near record breaking temperatures causing high demand throughout the entire western interconnection. On this date, the Companies set a new combined system peak load record of 8,384 MW. Climate related incidents such as this no longer appear to be isolated events.

In California, officials from the California Energy Commission, Public Utilities Commission, CAISO, and the office of Governor Gavin Newsom indicated in an online briefing on May 6, 2022, an expected capacity shortfall of about 1,800 MW in California in 2025.[19] As reported by Reuters:

> California's electricity planning has been challenged as devastating wildfires have cut off transmission lines and extreme heat events and drought have hampered hydropower supplies. Officials said

[18] *See* Docket No. 22-03001, March 1, 2022, Direct Testimony of Ryan Atkins at Q&A 25.
[19] https://www.reuters.com/world/us/california-says-it-needs-more-power-keep-lights-2022-05-06/

> traditional electricity demand forecasting does not account for such extreme events prompted by a changing climate.
>
> At the same time, many solar farms and energy storage projects the state has commissioned over the last two years were delayed due to supply chain challenges during the pandemic and a recent federal trade probe into solar imports.

While the Companies' concerns are similar to California's, the Companies' concerns continue to be compounded by the CAISO's change in day-ahead export priorities, implemented in the summer of 2021, and its ongoing Wheel Through Initiative. The change in export priorities allows CAISO to adjust day-ahead export schedules to zero with potentially less than an hour's notice on whether the energy will flow. The changes to Wheel Through priorities allow CAISO to prioritize use of Northwest imports to serve CAISO load, precluding short-term (less than 45-day) firm energy from being wheeled through California. These two items impact both the Companies and Open Access Transmission Tariff ("OATT") customers in Nevada. FERC issued an order extending the wheel-through policies approved for the summer of 2021 through May of 2024 and directed CAISO to report on progress towards a long-term approach. CAISO issued their straw proposal on July 29, 2022, with a final proposal not expected to be ready until February 2023. Accordingly, there is significant uncertainty as to what wheel-through rules will be adopted and, most significantly, what will be the amount of transmission capacity CAISO will claim on behalf of its "native load." Both of these items add significant risk to the market as a whole as the liquidity in the real-time hourly power market has been reduced significantly as more entities have joined the EIM.

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. Physical gas volumes are to be procured at indexed prices, subject to a cap [redacted] per MMBtu on the premium. This cap could be exceeded with prior approval from the Risk Committee; however, if the Companies exceed the premium cap and the procured gas which exceeded the premium cap is not the least cost supply alternative, the Companies will provide written notice to the Staff and BCP indicating such. As described in this ESP Update filing, the Companies are proposing to continue to follow the physical gas procurement strategy reviewed and approved in Docket No. 09-07003.

Figure ESP-35 reflects the historic and planned implementation of the physical gas acquisition strategy.

FIGURE ESP-35
PHYSICAL GAS ACQUISITION STRATEGY

	Delivery						
Incremental Transaction	Winter '21-'22	Summer '22	Winter '22-'23	Summer '23	Winter '23-'24	Summer '24	Winter '24-'25
Q1 '20	25%						
Q3 '20	25%	25%					
Q1 '21	25%	25%	25%				
Q3 '21	25%	25%	25%	25%			
Q1 '22		25%	25%	25%	25%		
Q3 '22			25%	25%	25%	25%	
Q1 '23				25%	25%	25%	25%
Q3 '23					25%	25%	25%
Q1 '24						25%	25%
Q3 '24							25%
Sum	100%	100%	100%	100%	100%	100%	100%

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

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 are well poised to access the dominant supply basins serving the Pacific Northwest and the Desert Southwest per their existing firm gas transportation assets. These gas supply basins are the Rocky Mountain Basin, the San Juan Basin, British Columbia, Western Canada Sedimentary Basins, as well as California gas supply. The gas transportation facilities that are available to move gas from the supply basins to Nevada Power's and Sierra's service territories are shown in Figures ESP-36 and ESP-37.

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

Sierra takes delivery of natural gas from two interstate pipelines, Great Basin and Tuscarora. Great Basin receives gas supplies upstream from 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 AECO producing areas to the Alberta/British Columbia border. There, TC Energy's Alberta system interconnects with TC Energy's Foothills system, which transports gas to GTN system at the U.S./Canadian border near Kingsgate, Idaho.

FIGURE ESP-36
NEVADA POWER PIPELINE ROUTES

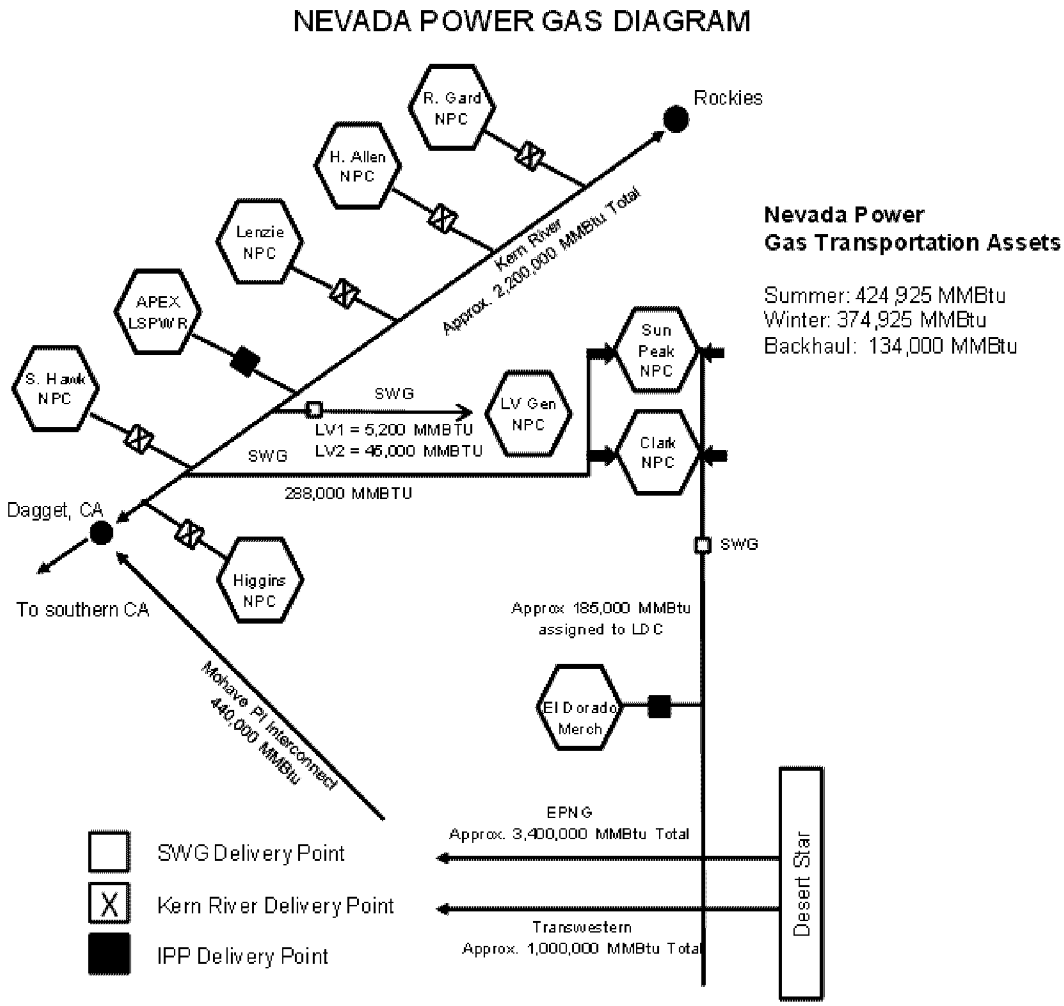
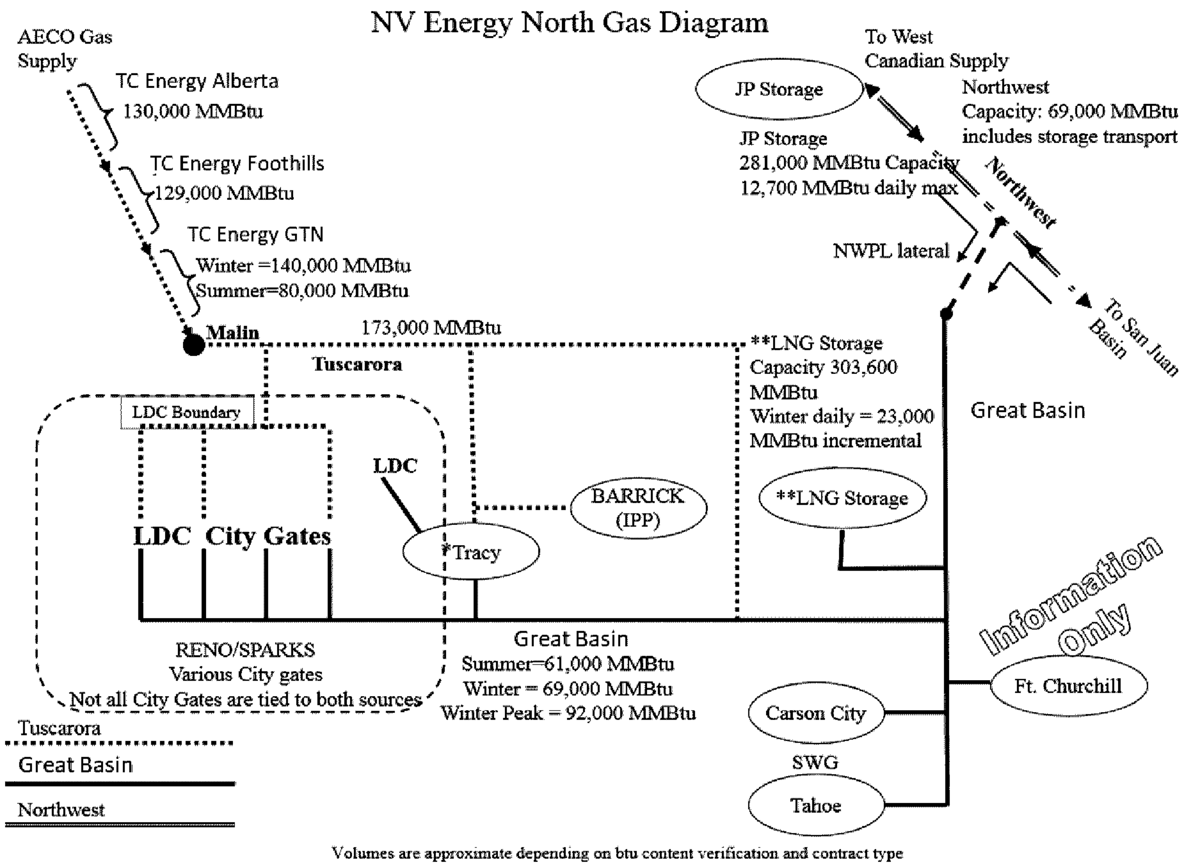


FIGURE ESP-37
SIERRA PIPELINE ROUTES



Figures ESP-38 and ESP-39 list Nevada Power's and Sierra's existing gas transportation service agreements.

FIGURE ESP-38
NEVADA POWER NATURAL GAS TRANSPORTATION CONTRACTS

Contract Type	Counterparty	Contract #	Termination Date	Daily Quantity (MMBTUs)	Summer	Comments
TSA	Kern River	20027	4/30/2028	75,000		
TSA	Kern River	20028	4/30/2028		50,000	
TSA	Kern River	20023	4/30/2032	12,500		
TSA	Kern River	20013	9/30/2031	11,075		
TSA	Kern River	20012	9/30/2031	10,350		
TSA	Kern River	1830	9/30/2031	266,000		Forward Haul
TSA	Kern River	1617	9/30/2031	134,000		Backhaul
Rental	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	7/31/2023	45,000		

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

Gas supplies for Nevada Power's Harry Allen, Chuck Lenzie, Higgins and Silverhawk plants are delivered directly by Kern River. The gas-fired units at Edward W. Clark Generating Station and Sun Peak Generating Station receive gas delivered under a 288,000 MMBtu/day transportation service agreement with Southwest Gas Corporation ("Southwest"). The transportation agreement with Southwest provides for receipt of Kern River supplies, as well as limited quantities of gas from sellers off the El Paso Natural Gas Company ("El Paso") and/or Transwestern Pipeline Company ("Transwestern") pipelines south of Las Vegas (if Southwest is not using its capacity rights to serve its own requirements). As part of the acquisition of Las Vegas Generating Station Unit 1 and 2 in 2014 (formerly known as LV Cogen), Nevada Power retained the gas transportation service agreements (LV Station Unit 1 45,000 MMBtu/day and LV Station Unit 2 5,200 MMBtu/day) with Southwest. The primary term for the LV Station Unit 2 contract with Southwest was extended through July 31, 2023.

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

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

FIGURE ESP-39
SIERRA NATURAL GAS TRANSPORTATION CONTRACTS

Contract Type	Counterparty	Contract #	Termination Date (as of 9/1/2022)	Units	Maximum Daily Quantity Annual	Winter	Summer
TSA							
	TC Energy - Alberta System						
		2010-447962	10/31/2025	GJ/Day	18,583		
		2010-447963	10/31/2025	GJ/Day	92,918		
		2010-447964	10/31/2025	GJ/Day	25,993		
					137,494		
	TC Energy - Foothills System						
		SPP-F1	10/31/2023	GJ/Day	32,444		
		SPP-F2	10/31/2023	GJ/Day	2,143		
		SPP-F3	10/31/2023	GJ/Day	5,572		
		SPP-F4	10/31/2023	GJ/Day	16,220		
		SPP-F5	10/31/2023	GJ/Day	10,920		
		SPP-F6	10/31/2023	GJ/Day	866		
		SPP-F7	10/31/2023	GJ/Day	26,233		
		SPP-F8	10/31/2023	GJ/Day	10,000		
		SPP-F9	10/31/2023	GJ/Day	15,826		
		SPP-F10	10/31/2023	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	6/30/2023	MMBTU/Day	59,696		
		10061	3/31/2023	MMBTU/Day	9,000		
					68,696		
	Great Basin Gas Transmission						
		F-29	11/30/2024	MMBTU/Day		68,696	61,044
		F-32	3/31/2025	MMBTU/Day		23,000	
						91,696	61,044
	TC Energy - Tuscarora						
		F001	12/31/2032	MMBTU/Day	105,750		
		F019	12/31/2032	MMBTU/Day	10,000		
		F024	12/31/2032	MMBTU/Day	5,661		
		F025	12/31/2032	MMBTU/Day	5,690		
		F030	12/31/2032	MMBTU/Day	5,722		
		F097	9/30/2030	MMBTU/Day	40,000		
		369	9/30/2030	MMBTU/Day	760		
					173,583		
Storage							
	Northwest Pipeline						
		126544 Storage Capacity	3/31/2046	MMBTU	281,242		
		126544 Storage Withdraw	3/31/2046	MMBTU/Day	12,687		
	Great Basin Gas Transmission						
		S-6 LNG Stor Cap	3/31/2025	MMBTU	303,604		
		S-6 LNG Daily Del Cap	3/31/2025	MMBTU/Day		23,000	

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

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

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

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

Sierra relies on annual evergreen rights and right of first refusal to keep existing gas transport capacity rights in place. In the 2022 ESP, Sierra is seeking approval to maintain its current natural gas transportation portfolio by renewing natural gas transportation contracts with evergreen rights that expire in 2023. The request to approve the renewal of contracts with evergreen rights that expire in 2023 enables Sierra to provide the pipelines with the required notice to renew them. The existing contracts subject to renewal are shown in Figure GIR-30.

Sierra has one contract with Great Basin, that expires on November 30, 2024, which is towards the end of the 2021 ESP action plan period.

In last year's GIR and ESP update, it was reported that Sierra was in pre-hearing settlement discussions with GTN regarding their requirement to file of a rate with the Federal Energy Regulatory Commission (FERC) by June 1, 2021, and that a settlement was not reached. However, a few days prior to Sierra's required June 1, 2021, filing date for the GIR and ESP filings, GTN and its shippers agreed to extend the negotiations. On September 29, 2021, GTN and its shippers agreed to a settlement which kept GTN's rates the same, with a moratorium for no rate increases through December 31, 2023.

Tuscarora was required by the FERC to file a rate no later than July 31, 2022. Tuscarora held pre-hearing settlement discussions beginning in April 2022, which Sierra participated in. A settlement was not reached during these discussions and therefore Tuscarora filed its rate case on July 29, 2022. Sierra will participate in this rate case and monitor this proceeding closely.

Sierra has been participating in pre-hearing settlement discussions since September 2021 with NWPL and its shippers. NWPL was required to file a rate case with the FERC by July 1, 2021. On June 29, 2022, NWPL reached a settlement in principle with its shippers. To provide more time to memorialize the settlement in principle, an unopposed petition to extend the rate case filing date was submitted to FERC. The petition was granted, extending the filing requirement from July 1, 2022, to August 31, 2022. At this time, NWPL plans on filing this settlement at the FERC by August 31, which will lower rates.

Sierra would not be able to serve its customers if the agreements with Great Basin and Tuscarora, which are directly connected to the LDC and power plants, are not renewed.

Sierra's analysis shows that failure to renew the Tuscarora contracts has two major drawbacks:

- Sierra loses: 1) the option of renewing the contract in subsequent years; and 2) potentially loses future access to the pipeline (if no capacity is available). As basis differentials between supply basin fundamentals change, without access to Alberta supply, Sierra will not have the ability to benefit from favorable pricing; and,

- Reduced reliability as it places the company at greater risk of a curtailment of gas distribution customers due to a lack of gas supply – a very high consequence event that could lead to the opening of emergency shelters, the activation of mutual assistance contracts and multi-million dollar relight cost potential.

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

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

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

C. RECOMMENDED GAS HEDGING PLAN

The Companies are seeking Commission approval of a hedging strategy for gas seasons summer 2023 thru winter 2024, 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 – COAL SUPPLY PLAN

A. CURRENT COAL PURCHASE & TRANSPORTATION AGREEMENTS

Qualified coal sources for North Valmy Station Units 1 and 2 include mines located in Central Utah, Western Colorado, and Southern Wyoming. Currently, Sierra has coal purchase agreements in place to provide enough supply through 2023. Coal is delivered under Sierra and Idaho Power Company's Rail Transportation Services Agreement with Union Pacific Railroad Company that provides for deliveries from various Central Utah, Western Colorado, Southern Wyoming and Powder River Basin origins to the North Valmy Station destination. Sierra, along with Idaho Power Company, leases two sets of railcars from Trinity Industries Leasing Company and Mitsui Rail Company to make up the trains used to deliver North Valmy Station's coal requirements.

B. COAL SUPPLY PLAN

Sierra plans to fill North Valmy Station coal requirements through RFPs transmitted to the list of qualified suppliers. Sierra plans to employ this process to provide coal supplies to support North Valmy Station's planned operations. Depending on forecasted coal burns and available coal supply, short term contracts of two years and under will be considered to supply Valmy's coal needs. Due to the planned 2025 retirement date of both Valmy units, Sierra will not solicit or enter into any longer-term coal supply agreements.

As discussed in the 2018 Life Span Analysis Plan ("LSAP") (Docket No. 18-06003), Valmy generation is critical to the transmission systems' reliability in northeastern Nevada. Valmy generation provides both capacity and critical voltage support to the 350+ MW Carlin Trend area load pocket. Valmy generation is so critical due to its location on the transmission grid and the lack of any other substantial NV Energy owned or contracted resources in the area.

Sierra will monitor North Valmy Station's unit operations, coal stockpile levels, coal burn forecast updates, and scheduled must run conditions to assess the requirement for additional supplies of coal. Sierra will continue to rely on short term purchases acquired via its RFP Process to supply the needed coal. In line with the goal of providing coal shipments that enable the plant to operate efficiently while meeting all required environmental regulations, coal quality parameters of all candidate coal sources are screened and reviewed with the plant.

SECTION 7 – 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, and the Risk Control Organization, which is described in the direct testimony of Mr. Michael Cole.

Four areas are involved in the Companies' risk management and control processes:

1) **Risk Committee.** The Risk Committee 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 Senior Vice President-Renewables and Origination, Vice President-Generation and the Director-Trading Analytics and Operations, are responsible for the generation production, delivery and optimization of fuel and wholesale power transactions.

3) **Risk Control.** The Risk Control function 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 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 Renewable Energy & Origination, 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 energy supply plan. 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 in order 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 Energy Supply Plan or Energy Supply Plan Update in accordance with NAC § 704.9504 and accept the obligation to modify the strategy as conditions warrant.

SECTION 8 – 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 PROMOD production cost forecasting model, Figure ESP-40 shows the estimated cost-to-serve for the recommended unhedged scenario under base, high, and low fuel and purchased power pricing scenarios.

FIGURE ESP-40
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 ($000)	Cost to Serve Assuming Base F&PP Prices ($000)	Cost to Serve Assuming High F&PP Prices ($000)
2023	$1,645,158	$1,919,319	$2,401,916
2024	$1,334,649	$1,517,679	$1,872,756

The Companies also calculated the projected Base Tariff Energy Rates ("BTER") and Deferred Energy Accounting Adjustment ("DEAA") rates for 2022-2024 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, as specified in the Forward Sales Procedures Manual (Technical Appendix POWER-1).

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. Over the past several years, the Commission has implemented an ESP process and the Companies' credit has improved. Currently, the Companies are able to finance this ESP without impairing their creditworthiness, assuming timely recovery under the Commission's current rate recovery mechanisms.

SECTION 9 – COMMISSION DIRECTIVES

A. 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 two quarters of 2021 and the first quarter of 2022 are included as Technical Appendix GAS-1.

B. WHITE PINE PUMPED STORAGE HYDRO PROJECT UPDATE

Development Services Agreement

The Companies continue negotiations with rPlus Energies ("rPlus") to finalize a Development Services Agreement ("DSA") for the project. Both parties have agreed to all the terms and conditions for the DSA except for the appropriate developer fee. As discussed in the initial filing for Docket 22-03024, once the DSA is signed the Companies will pay rPlus $2.5 million as a good faith payment. The DSA contemplates that rPlus will expend up to $25 million in this due diligence phase of development. The $2.5 million will be the Companies' contribution to the ongoing development efforts described below. Of the $1 million that was identified for the Companies' purposes for independent project due diligence, technical review of rPlus activities, and negotiation of project design, procurement, construction agreements and related documents, the Companies have expended $26,217 for internal labor and $28,140 for contracted legal expenses (January to July). Pending the outcome of the due diligence, the Companies tentatively expect to file with the Commission for the full approval to construct the project in the 2024 IRP filing.

Engineering & Design

A consulting engineering firm, Mott MacDonald, has been contracted by rPlus to assist with the preliminary engineering and design of the project. Mott MacDonald delivered a Draft Feasibility Study for the project in April of this year. The initial development costs remain the same as was previously estimated, which was a balance of approximately $70-$75 million that will be spent by the time the Notice to Proceed is issued by the FERC, including a $35 million equipment deposit in 2025. The updated cost estimate for the entire project remains close to the previous estimate of $2.6 billion that was provided in the initial filing. The updated estimate is at an Association for the Advancement of Cost Engineering ("AACE") Class 4[20] level of accuracy. The prior estimate was at AACE Class 5.

The Final Feasibility Study will be completed following completion of the next phase of geotechnical investigation (see below) and it is expected that the construction cost estimate will be at the AACE Class 3 level of accuracy at that time.

Geotechnical Investigation

Borehole #2 ("BH2") was drilled in 2021 and the geotechnical analysis has been completed on it. Two additional boreholes – designated BH1 and BH3 – were planned to be completed in the fall of 2022. In addition to having these boreholes drilled and the associated testing that occurs with the drilling, geophysical testing is planned to occur on the site. To allow sufficient time to complete these boreholes, rPlus applied for a seasonal activity waiver from the Nevada Department of Wildlife to allow activity to begin on September 1, 2022. This request was granted. Mobilization for a seismic reflection survey at the lower reservoir site will begin before Labor Day (September 5) and the survey is expected to be completed by September 15. Following that survey, the BH1 borehole crew will be mobilized, and drilling is planned to begin October 1 and conclude by

[20] The expected accuracy range of a AACE Class 5 estimate is -50% to +100%, a Class 4 estimate is -30% to +50%, a Class 3 estimate is -20% to +30%

October 15. These surveys will serve to confirm understanding of subsurface conditions and fault trace locations in a key project location.

BH3, located at the upper reservoir site of the project and would extend down to the powerhouse level, would provide information on the vertical shaft that will be constructed. rPlus decided not to pursue drilling BH3 at this stage of development because of the high cost of drilling it and the belief that BH3 has a less significant contribution to the fatal flaw assessment study than the other two boreholes. A new and permanent access route to BH3 from the Steptoe Valley side, going entirely through BLM land, has been defined by rPlus and its engineers and will be used as an alternate access route from the preferred Duck Valley side.

However, the western access road is suitable to allow for the planned seismic refraction survey at the upper reservoir location, which is expected to take 4 to 5 days and will be conducted following the geophysical survey at the lower site.

The 2022 geotechnical investigation will be concluded by October 31, 2022, followed by analysis and reporting, which will feed into the Final Feasibility Study.

Water

On June 10^{th}, 2022, rPlus received notice from the Nevada Division of Water Resources that its applications to change the point of diversion for the water that will be sold by White Pine County to the Project for construction, initial fill, and long-term make-up to the reservoirs had been deemed complete. Permit fees in the amount of $26,664 were paid. rPlus is awaiting approval of these applications by the State Engineer's Office.

A plan for hydrogeological investigation in the vicinity of the proposed well locations is being prepared for submission to the BLM.

Environmental/Permitting: FERC Licensing

rPlus received several comments and requests for additional studies as a result of its Draft License Application ("DLA") with FERC, which was filed on February 17, 2022. A number of studies are in the planning or implementation stage to address those requests in anticipation of filing a Final License Application ("FLA") in Q4 2022. The original planned FLA filing date was approximately August 1, but rPlus determined that allowing additional time for a more complete application would increase the chances of qualifying for the expedited licensing process while addressing more stakeholder concerns earlier.

To address the issues raised in the comments received from the DLA filing, a meeting was held on August 2, 2022, in Ely, Nevada between representatives of rPlus, the Nevada Northern Railway, and the National Parks Service to address concerns raised by the Railway. A plan for conducting a survey of railroad visitors, along with photo-simulations of what the project will look like to passengers, was developed at the meeting.

Environmental/Permitting: Other

In September 2022, rPlus plans to file a request for an amendment to the current Resource Management Plan ("RMP") that governs the activities allowed in specific locations associated with sage grouse habitat and the timing of those activities. This amendment is required to allow for sufficiently large windows throughout the year for construction of the Project within a reasonable time frame. The Plan of Development ("POD"), submitted to the BLM, must be updated prior to requesting amendment of the RMP. POD updates are in progress and expected to be completed in August 2022.

Regulatory/Market/Finance

The Inflation Reduction Act signed by President Biden on August 16, 2022, includes provision for an Investment Tax Credit for standalone energy storage, including pumped storage hydro. The Companies expect that the White Pine Pumped Storage project would qualify for a 30 percent base investment tax credit and possibly an additional 10 percent tax credit for meeting a 40 percent domestic content requirement. rPlus continues to assess the implications of the bill for the project.