BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the First Amendment to the 2021 Joint Integrated Resource Plan.	Docket No. 22-03___

VOLUME 1 OF 4

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

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TRANSMITTAL LETTER

March 18, 2022

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

RE: Docket No. 22-03___- Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of its First Amendment to the 2021 Joint IRP.

Dear Ms. Osborne:

Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (the "Companies") hereby submit this Joint Application for approval of the First Amendment to the 2021 Joint Integrated Resource Plan (approved by the Public Utilities Commission of Nevada ("Commission") in Docket No. 21-06001). This First Amendment requests to update and modify the Supply Plan and receive Commission approval to further investigate a pumped storage hydro project.

The Companies have included with this Application and incorporate herein by reference the following Application Exhibits:

- **Application Exhibit A** is a narrative discussion of the Companies' requests with supporting information.

- **Application Exhibit B** is a proposed notice of the Application as required by NAC § 703.162.

- **Application Exhibit C** is an updated loads and resources table.

In addition, the Joint Application is supported by Technical Appendices and prepared direct testimony from the following witnesses:

- **John (Jack) P. McGinley**
- **Ryan Atkins**
- **John Frankovich**
- **Dr. David Harrison, Jr.**
- **Anita Hart**
- **Kimberly Hopps**
- **John Lescenski**
- **Charles Pottey**
- **Shane Pritchard**
- **Zack Vukanovic**
- **Mark Warden**

Certain information set forth in testimony, the narrative and Technical Appendices is commercially confidential and/or trade secret information subject to protection pursuant to NRS § 703.190. Specifically, the confidential information in this filing, along with the basis for the assertion of confidentiality, is set forth below.

Fuel and Purchased Power Price Forecasts. Technical Appendix FPP-1 as well as price forecast charts presented in the Fuel and Purchased Power Price Forecasts section of the narrative contain commercially sensitive and/or trade secret information that derives independent economic value from not being generally known and are derived using proprietary information of third parties. This confidential information is obtained from Wood Mackenzie Limited ("WoodMac"), a fee subscription service and recognized provider and consultant for the energy industry, and cannot be publicly disclosed. This information is protected by confidential provisions between the Companies and WoodMac, and contains essential qualitative descriptions of the assumptions and methodologies used to develop the price projections. Similarly, the Companies purchase and sell energy and capacity in the wholesale market. In seeking or responding to requests for proposal ("RFP"), the confidentiality of the Companies' price forecasts is key to the competitive process. Therefore, it is fundamentally contrary to the interests of customers to provide public access to Companies' confidential price forecasts for market energy and fuels.

Renewable Plan. Technical Appendices REN-3 through REN-10 contain confidential information. Technical Appendices REN-3 and REN-4 are publicly accessible with the exception of the North Valley geothermal power purchase agreement ("PPA") pricing, which has been redacted at the developer's request. The PPA is competitively priced and represents one of the best values the Companies have been able to receive for a geothermal resource. The project's developer is currently in negotiations with a number of out-of-state load-serving entities for its other geothermal resources. Disclosure of the North Valley PPA pricing information will undermine the developer's negotiating position with those other entities which will in turn create a disincentive for the developer to enter into competitively priced PPAs with the Companies in the future. Such a disincentive will negatively affect the Companies' ability to negotiate the best terms and secure diverse renewable resources for their customers. Technical Appendix REN-5 is confidential as it contains the Companies' due diligence review of the North Valley project, which, if publicly disclosed, could provide an unfair market advantage to competitors by showing the Companies' internal analysis of projects. Confidentiality of the Companies' technical evaluation of bids is essential to future successful negotiations and competitive solicitations.

Technical Appendices REN-6 and REN-7 contain the manufacturer's costs of the battery energy storage system ("BESS") to be located at the former site of the Reid Gardner Generating Station. Public disclosure of such information could negatively impact the Companies' ability to obtain competitive pricing from vendors in the future. The emerging market with dynamic prices for energy storage is highly competitive and not mature where all technologies are directly comparable. Disclosure of the exact construction cost breakdown may provide a false threshold for market competitiveness because there are other terms that contribute to the analysis of the value of the overall project, such as commodity cost curves, overbuild, efficiency, augmentation strategies, service agreements, and warranties. Technical Appendix

REN-8 contains the Companies' assessment of candidate projects sites not selected and contains developer information, including costs, shared under a protective agreement. Technical Appendix REN-9 contains a screening-level cost comparison of the 2-hour BESS and a combined-cycle facility. This comparison was completed after the Companies' due diligence efforts for a combined-cycle facility evaluated as part of the fall 2021 Open Resource Request for Proposals. The project was not selected, and its costs were shared under a protective agreement. Disclosure of confidential cost and bid information contained in Technical Appendices REN-8 and REN-9 could negatively impact the Companies' ability to obtain competitive offers from bidders in the future.

Technical Appendix REN-10 supports the Companies' request for funding further investigation into a pumped storage hydroelectric project to be located in White Pine County, Nevada (the "White Pine"). Technical Appendix REN-10 is confidential as it contains pricing details of comparable projects and studies that are not available in the public domain. Public disclosure of this information could allow a competitor to determine the confidential forecasts and assumptions and may impact the Companies' ability to negotiate in the marketplace and obtain the best terms and pricing for their customers. The pricing details from confidential Technical Appendix REN-10 present in testimony and narrative are redacted. Estimated costs associated with the development and operation of White Pine are third-party commercially sensitive information. The project costs are subject to the ongoing negotiations between the developer of the project and the Companies. The Companies are not requesting approval of those costs, or of the White Pine itself, with this filing and the estimated costs are being presented for informational purposes only. Finally, while the Companies are publicly disclosing the $3.5 million amount necessary to move the White Pine project forward, the exact amount of the payment to the developer of the project to offset due diligence costs and for the Companies to receive exclusive rights to purchase the project should be confidential. The developer payment amount represents commercially sensitive information and was arrived at as a result of confidential negotiations. Disclosure of such information may impair the Companies' ability to negotiate for the best terms in the marketplace the future.

Generation Plan. Technical Appendices GEN-1 and GEN-2 are marked as confidential. Technical Appendix GEN-1 contains confidential cost and performance data. Technical Appendix GEN-2 includes confidential information regarding the Companies' estimated performance of potential future resources. These confidential technical appendices contain commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets and its future procurement opportunities. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage the Companies and their customers by limiting their ability to foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing bargaining leverage. Publication of this information would unfairly advantage competing suppliers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers.

Economic Plan. Technical Appendices ECON-3 and ECON-6 are confidential. Technical Appendix ECON-3 contains the average cost of energy from each of the Companies' generators. Costs specific to each generator are considered commercially-sensitive information. Disclosure of such information could put the Companies at a competitive disadvantage. Technical Appendix ECON-6 contains sensitive projected capital cost information related to conventional placeholder resources. Public disclosure could harm the Companies' ability to negotiate the best priced contracts moving forward and would put the Companies at a competitive disadvantage.

Financial Plan. Certain figures in the Financial Plan of the Narrative are confidential. Specifically, Figures FP-3 and FP-4 in the External Financing Requirements section of the Financial Plan and Figures FP-11 through FP-18 in the Credit Quality section of the Financial Plan should be treated as confidential. Sierra and Nevada Power's debt is publicly traded and the information identified in the figures above have not been previously disclosed to the public. Public disclosure of this information could influence investor's view of the underlying credit quality of and debt pricing for the Companies.

Pursuant to NAC § 703.5274(1), one unredacted copy of the confidential information will be printed and 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.

The Companies request that designated information remain confidential for a period of at least 5 years, after which it may be destroyed or returned to the Companies, whichever is more convenient for the Commission. Confidential treatment of the above-described information will not impair the ability of the Regulatory Operations Staff or the Bureau of Consumer Protection to fully investigate the Companies' proposals.

Should you have any questions regarding this filing, please contact me at 775-834-3470 or at Roman.Borisov@nvenergy.com.

Sincerely,

/s/ Roman Borisov
Roman Borisov
Senior Attorney

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

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- John Frankovich

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ECON-8	PROMOD Area Diagram
ECON-9	NERA Report

CERTIFICATE OF SERVICE

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

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. 22-03___ upon the persons listed below by electronic mail:

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Attorney General's Office
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Las Vegas, NV 89148
bcpserv@ag.nv.gov

DATED this 18th day of March, 2022.

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

APPLICATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the First Amendment to the 2021 Joint Integrated Resource Plan.	)))))	Docket No. 22-03___

JOINT APPLICATION TO APPROVE THE FIRST AMENDMENT TO 2021 TRIENNIAL INTEGRATED RESOURCE PLAN

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 joint Application, pursuant to Nevada Revised Statute ("NRS") § 704.741 *et seq*., and Nevada Administrative Code ("NAC") § 704.9005 *et seq*. for approval by the Public Utilities Commission of Nevada ("Commission") of the Companies' First Amendment ("Amendment") to their 2021 joint triennial integrated resource plan ("2021 Joint IRP"). As this is an amendment to the Companies' 2021 Joint IRP, NRS § 704.751(2)(a) requires that that Commission issue an order accepting or modifying the Amendment, or specifying any portions of the Amendment it deems to be inadequate, within 165 days after its filing. The statutory period within which this matter must be resolved therefore runs on August 30, 2022.

I.

SUMMARY AND INTRODUCTION

Recently-approved IRPs have positioned the Companies to meet the state's decarbonization goals, while also addressing changes in climate, weather, and resource variability. However, shifts in weather and a rapidly changing resource mix in the Western United States contribute to ever decreasing confidence in the availability and deliverability of market capacity, on which the Companies have historically relied to serve their load. While the 2021 Joint IRP reduced the reliance on market capacity relative to prior plans, further reduction on market reliance is required to diminish risk and ensure resource adequacy. This Amendment addresses increasing concerns regarding the availability and deliverability of market capacity and energy, and adding resources in the balancing area that provide price stability.

This Amendment also addresses the importance of energy storage needed to meet the state's energy policies. The Amendment proposes a new utility-scale battery project and examination of a pumped storage hydro project to diversify energy storage resources. Energy storage will continue to play a critical role in facilitating efficient deployment of renewable energy resources in the future. Energy storage allows NV Energy to store excess solar energy produced in the day and use it later when the energy is most needed to serve our customers.

The Companies designed their Preferred Plan to address the above challenges and meet the stated objectives. Accordingly, the Amendment seeks approval of the following:

- A new long-term fuel and purchased power price forecasts;
- Construction of a 2-hour battery energy storage system ("BESS") with a capacity of 220 megawatts ("MW") at the site of the former Reid Gardner Generating Station;
- A $3.5 million funding request to further study and perform due diligence on the pumped storage hydro project with a capacity of 1,000 MW located in White Pine County, Nevada (the "White Pine");
- A power purchase agreement ("PPA") for 25 MW of geothermal generation;
- Peak firing project upgrades at the existing generating units at Tracy, Chuck Lenzie, and Harry Allen generating stations to yield 48 MW of additional on-peak generation;
- Thermal energy storage project at the Chuck Lenzie Generating Station to increase the station's peak capacity by 18 MW; and
- Network upgrades needed to support the interconnection of the proposed BESS at the Reid Gardner Generating Station.

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

II.

THE APPLICANTS

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:

Roman Borisov
Senior Attorney
6100 Neil Road
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775-834-3470
Roman.Borisov@nvenergy.com

Aaron Schaar
Manager, Regulatory Services
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775-834-5823
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III.

APPLICATION EXHIBITS

To aid the Commission in considering the First Amendment, the Companies have included with this Application and incorporated herein by reference the following exhibits:

- **Application Exhibit A** is a Narrative discussion of (1) the load and fuel and purchased power price forecasts; (2) the generation, renewable, and transmission portions of the Supply Plan; (3) an economic analysis of the Preferred Plan; and (4) the Financial Plan.

- **Application Exhibit B** is a proposed notice of the Application as required by NAC § 703.162.
- **Application Exhibit C** is an updated loads and resources table.

The form of Exhibit A, the Narrative, was selected because it is the form used in IRPs and IRP amendments to provide the Commission and stakeholders with detailed and technical information regarding the inputs, in-depth descriptions of the analytical techniques applied to the questions to be answered in IRP filings, as well as clear communication of the results of IRP filings and the recommendations for Commission approval.

IV.

ADDITIONAL SUPPORTING MATERIAL

NAC § 704.9321(1) provides that a utility's resource plan must be based on substantially accurate data, adequately demonstrated and defended, and adequately documented and justified. NAC § 704.922 provides that a utility's resource plan must include technical appendices containing sufficient detail to enable a technically proficient reader to understand how the IRP was prepared, and to evaluate the validity of the assumptions and accuracy of the data used. NAC § 704.5664 requires that a utility's resource plan must include written testimony in support of the resource plan.

Consistent with these directives, the Amendment includes all such additional material required to adequately demonstrate and defend the substantially accurate data supporting the analysis and the requests for affirmative relief set forth herein. The Amendment and requested information are supported by the following witnesses' prepared direct testimony:

John (Jack) P. McGinley, Vice President, Regulatory, is the executive sponsor of the Amendment.

Ryan Atkins, Director of Trading, Analytics and Operations, formulates the justification related to market capacity concerns for the Companies' Amendment to their 2021 Joint IRP and sponsors Sierra's coal price forecast.

John Frankovich, Project Director, Renewable Energy & Origination, sponsors the request to approve the BESS at the site of the former Reid Gardner Generating Station. Mr. Frankovich sponsors Technical Appendices REN-6 through REN-9.

Dr. David Harrison, Jr., Economist and Senior Vice President at NERA Economic Consulting, sponsors the discussion and analysis of environmental externalities contained in the Economic Analysis section and Technical Appendix ECON-9.

Anita Hart, Director Resource Planning & Analysis, sponsors the economic analysis performed in the evaluation of the resource plans considered in this Amendment to the 2021 Joint IRP. In addition, Ms. Hart, together with Dr. David Harrison, supports the environmental and externalities results contained in Technical Appendix ECON-9. Ms. Hart sponsors Technical Appendices ECON-1 through ECON-9.

Kimberly Hopps, Assistant Treasurer, sponsors the Financial Plan of the narrative, provides an overview of the Preferred and Alternate Plans' capital commitments and associated financial impacts. In addition, Ms. Hopps provides a detailed discussion of the Companies' financial plans associated with the Preferred and Alternate Plans, including capital spending projections, funding requirements, credit metric impacts and customer rate impacts.

John Lescenski, **Manager of Generation Engineering and Technical Services**, supports the Generation section of the Supply Plan narrative. Mr. Lescenski addresses the wet compression upgrade projects and the Companies' requests for approval of generation investments to install peak firing project upgrades on the combined-cycle units at the Tracy, Chuck Lenzie, and Harry Allen generating stations, as well as chilled water storage at the Chuck Lenzie Generating Station. As part of the Alternate Plan presentation, Mr. Lescenski discusses the Silverhawk Peaking Plant. Mr. Lescenski sponsors Technical Appendices GEN-1 and GEN-2.

Charles Pottey, Director of Transmission and Distribution Planning, sponsors the Transmission Plan additions to support interconnection of the North Valley geothermal facility and the BESS to be located at the site of the former Reid Gardner Generating Station. Mr. Pottey

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

also describes the Remedial Action Scheme proposed for the North Valmy Generating Station. Mr. Pottey sponsors Technical Appendices TRAN-1 and TRAN-2.

Shane Pritchard, Director Renewable Energy & Origination, sponsors the Renewable Plan and supports the Companies' plan for complying with Nevada's renewable portfolio standard. Mr. Pritchard also supports the approval of the PPA for 25 MW of renewable energy from the North Valley geothermal facility in Washoe County, Nevada. Mr. Pritchard sponsors Technical Appendices REN-1 through REN-5.

Zeljko Vukanovic, Market Fundamentals Lead, sponsors the wholesale power and natural gas price forecasts presented in Section 4 of the narrative. Mr. Vukanovic sponsors Technical Appendix FPP-1.

Mark Warden, **Director of Renewables Sourcing**, supports the Companies' request for $3.5 million to support the developer's continued development and perform the Companies' due diligence on the White Pine pumped storage hydro project. Mr. Warden sponsors Technical Appendices REN-10 and REN-11.

V.

CONFIDENTIALITY

Certain information set forth in the Narrative and Technical Appendices is commercially sensitive and/or trade secret information subject to protection pursuant to NRS § 703.190. Specifically, the confidential information in this filing, along with the basis for the assertion of confidentiality, is set forth below.

Fuel and Purchased Power Price Forecasts. Technical Appendix FPP-1 as well as price forecast charts presented in the Fuel and Purchased Power Price Forecasts section of the narrative contain commercially sensitive and/or trade secret information that derives independent economic value from not being generally known and are derived using proprietary information of third parties. This confidential information is obtained from Wood Mackenzie Limited ("WoodMac"), a fee subscription service and recognized provider and consultant for the energy industry, and cannot be publicly disclosed. This information is protected by confidential provisions between the

Nevada Power Company
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Companies and WoodMac, and contains essential qualitative descriptions of the assumptions and methodologies used to develop the price projections. Similarly, the Companies purchase and sell energy and capacity in the wholesale market. In seeking or responding to requests for proposals ("RFPs"), the confidentiality of the Companies' price forecasts is key to the competitive process. Therefore, it is fundamentally contrary to the interests of customers to provide public access to Companies' confidential price forecasts for market energy and fuels.

Renewable Plan. Technical Appendices REN-3 through REN-10 contain confidential information. Technical Appendices REN-3 and REN-4 are publicly accessible with the exception of the North Valley PPA pricing, which has been redacted at the request of the developer. The PPA is competitively priced and represents one of the best values the Companies have been able to receive for a geothermal resource. The project's developer is currently in negotiations with a number of out-of-state load-serving entities for its other geothermal resources. Disclosure of the North Valley PPA pricing information will undermine the developer's negotiating position with those other entities which will in turn create a disincentive for the developer to enter into competitively priced PPAs with the Companies in the future. Such a disincentive will negatively affect the Companies' ability to negotiate the best terms and secure diverse renewable resources for their customers. Technical Appendix REN-5 is confidential as it contains the Companies' due diligence review of the North Valley project, which, if publicly disclosed, could provide an unfair market advantage to competitors by showing the Companies' internal analysis of projects. Confidentiality of the Companies' technical evaluation of bids is essential to future successful negotiations and competitive solicitations.

Technical Appendices REN-6 and REN-7 contain the BESS manufacturer's costs public disclosure of which could negatively impact the Companies' ability to obtain competitive pricing from vendors in the future. The emerging market with dynamic prices for energy storage is highly competitive and not mature where all technologies are directly comparable. Disclosure of the exact construction cost breakdown may provide a false threshold for market competitiveness because there are other terms that contribute to the analysis of the value of the overall project, such as commodity cost curves, overbuild, efficiency, augmentation strategies, service agreements, and warranties. Technical Appendix REN-8 contains the Companies' assessment of candidate projects sites not selected and contains developer information, including costs, shared under a protective agreement. Technical Appendix REN-9 contains a screening-level cost comparison of the 2-hour BESS and a combined-cycle facility. This comparison was completed after the Companies' due diligence efforts for a combined-cycle facility evaluated as part of the fall 2021 Open Resource Request for Proposals. The project was not selected, and its costs were shared under a protective agreement. Disclosure of confidential cost and bid information contained in Technical Appendices REN-8 and REN-9 could negatively impact the Companies' ability to obtain competitive offers from bidders in the future.

Technical Appendix REN-10 is confidential as it contains pricing details of comparable to the White Pine pumped storage hydropower projects and studies that are not available in the public domain. Public disclosure of this information could allow a competitor to determine the confidential forecasts and assumptions and may impact the Companies' ability to negotiate in the marketplace and obtain the best terms and pricing for their customers. The pricing details from confidential Technical Appendix REN-10 present in testimony and narrative are redacted. Estimated costs associated with the development and operation of the White Pine are third-party commercially sensitive information. The project costs are subject to the ongoing negotiations between the developer of the project and the Companies. The Companies are not requesting approval of those costs, or of the White Pine itself, with this filing and the estimated costs are being presented for informational purposes only. Finally, while the Companies are publicly disclosing the $3.5 million amount necessary to move the White Pine project forward, the exact amount of the payment to the developer of the project to offset due diligence costs and for the Companies to receive exclusive rights to purchase the project should be confidential. The developer payment amount represents commercially sensitive information and was arrived at as a result of confidential negotiations. Disclosure of such information may impair the Companies' ability to negotiate for the best terms in the marketplace the future.

Generation Plan. Technical Appendices GEN-1 and GEN-2 are marked as confidential. Technical Appendix GEN-1 contains confidential cost and performance data. Technical Appendix GEN-2 includes confidential information regarding the Companies' estimated performance of potential future resources. These confidential technical appendices contain commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets and its future procurement opportunities. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage the Companies and their customers by limiting their ability to foster competition among prospective suppliers, compromising the Companies' negotiating position and reducing bargaining leverage. Publication of this information would unfairly advantage competing suppliers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers.

Economic Plan. Technical Appendices ECON-3 and ECON-6 are confidential. Technical Appendix ECON-3 contains the average cost of energy from each of the Companies' generators. Costs specific to each generator are considered commercially-sensitive information. Disclosure of such information could put the Companies at a competitive disadvantage. Technical Appendix ECON-6 contains sensitive projected capital cost information related to conventional placeholder resources. Public disclosure could harm the Companies' ability to negotiate the best priced contracts moving forward and would put the Companies at a competitive disadvantage.

Financial Plan. Certain figures in the Financial Plan of the narrative are confidential. Specifically, Figures FP-3 and FP-4 in the External Financing Requirements section of the Financial Plan and Figures FP-11 through FP-18 in the Credit Quality section of the Financial Plan should be treated as confidential. Sierra and Nevada Power's debt is publicly traded, and the information identified in the figures above have not been previously disclosed to the public. Public disclosure of this information could influence investor's view of the underlying credit quality of and debt pricing for the Companies.

Pursuant to NAC § 703.5274(1), one unredacted copy of the confidential information will be printed and 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.

The Companies request that designated information remain confidential for a period of at least five years, after which it may be destroyed or returned to the Companies, whichever is more convenient for the Commission. Confidential treatment of the above-described information will not impair the ability of the Regulatory Operations Staff of the Commission or the Attorney General's Bureau of Consumer Protection to fully investigate the Companies' proposals.

VI.

PRAYER

NAC § 704.9516(1)(a) requires that an amendment to an Action Plan include a section that identifies the items for which the applicant is requesting specific approval. In compliance with this provision of the IRP regulations, Sierra and Nevada Power are making the following specific requests:

1. Approval of the First Amendment to the 2021 Joint IRP base long-term fuel and purchase power price forecasts provided in Technical Appendix FPP-1 as presenting the most accurate information upon which to base the planning decisions set forth in the filing.
2. Approval of the Companies' Preferred Plan, including the resources listed below:
   a. A Supply Plan addition of the 2-hour, lithium-ion BESS with a capacity of 220 MW at the site of the former Reid Gardner Generating Station. Commercial operation is expected by May 31, 2023, at a cost of approximately $217 million and will be owned by Nevada Power. The price of the 2-hour battery is tied to the price of lithium through June 2022 and is, thus, subject to change up or down.

b. A Supply Plan addition of the North Valley geothermal facility PPA for 25 MW of renewable energy. Commercial operation is expected in December 2022, with a 25-year term at a flat energy price stated in the narrative.

c. A Supply Plan peak firing project upgrade on the Chuck Lenzie Generating Station units 1 through 4 (Blocks 1 and 2), increasing the station's total peak capacity by approximately 24 MW with an in-service date of May 2024. The project cost is estimated at $12 million.

d. A Supply Plan peak firing project upgrade on the Harry Allen Generating Station units 5 and 6, increasing the station's total peak capacity by approximately 12 MW with an in-service date of May 2024. The project cost is estimated at $6 million.

e. A Supply Plan peak firing project upgrade on the Tracy Generating Station units 5 and 6, increasing the station's total peak capacity by approximately 12 MW with an in-service date of May 2024. The project cost is estimated at $6 million.

f. A Supply Plan thermal energy storage project at the Chuck Lenzie Generating Station, increasing the station's peak capacity by approximately 18 MW with an in-service date of May 2024. The project cost is estimated at $13 million.

g. A Transmission Plan project to construct the network upgrades to facilitate the interconnection of the BESS at the Reid Gardner substation. The network upgrade costs are estimated at $2.5 million.

3. Approval of $3.5 million to support the project developer's continued progress and perform the Companies' due diligence on a pumped storage hydro project located in White Pine County, Nevada. In addition, this expenditure secures the Companies' exclusive right to acquire the project.

4. Grant the Companies' request to maintain the confidentiality of the information as provided above;

5. Grant any other requests as are specifically set forth in the testimony and exhibits

filed herewith; and

6. Grant such additional other relief as the Commission may deem appropriate and necessary.

Dated this 18th day of March, 2022.

Respectfully submitted,

NEVADA POWER COMPANY
SIERRA PACIFIC POWER COMPANY

<u>/s/ Roman Borisov</u>
Senior Attorney
Nevada Power Company
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APPLICATION EXHIBIT A

NARRATIVE

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SECTION 1. INTRODUCTION

Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy") are filing this First Amendment to their 2021 joint integrated resource plan ("2021 Joint IRP").

Pursuant to NRS § 704.744, the Companies met on January 26, 2022, with the Commission's Regulatory Operations Staff ("Staff"), the Bureau of Consumer Protection ("BCP") and interested parties to present its preliminary key modeling assumptions and to provide an overview of the anticipated filing. Notice from the meeting can be found in Technical Appendix ECON-1.

This filing continues the evolution of Nevada's energy industry and market, addressing emergent concerns about the uncertain availability of regional market capacity and the need to diversify energy storage to advance a decarbonized future. The First Amendment seeks approval of a new fuel and purchase power price forecast, to amend the Generation plan with the addition of 66 megawatts ("MW") of upgrades to existing combustion turbines, to amend the Renewable plan to add a 220 MW grid-tied battery energy storage system ("BESS") and to fund a study of a pumped storage hydro project (currently under development by a third party) and a new 25 MW long-term power purchase agreement ("PPA") between Sierra and Ormat, and to amend the Transmission plan to add infrastructure necessary for interconnection of the renewable projects presented.

Recent integrated resource plans ("IRP") have put the Companies on strong footing as the state embarks on decarbonization goals, while also addressing changes in climate, weather, and resource variability. For example, to address these changes, the Fourth Amendment to the 2018 Joint IRP updated the use of Effective Load Carrying Capability ("ELCC") to better address the increasing quantities of variable renewable resources, and the 2021 Joint IRP made use of new trended weather load forecasts, a new method of evaluating the hour with the largest open position in the energy supply plan, and an updated planning reserve margin ("PRM"), while also reducing reliance on market capacity. However, recent events and industry reports contribute to ever decreasing confidence in the availability and deliverability of market capacity to Nevada. While the 2021 Joint IRP reduced the reliance on market capacity relative to prior plans, there is concern that further reduction is required to reduce risk and ensure resource adequacy. This Amendment addresses increasing concerns regarding the availability and deliverability of market capacity and energy by adding resources that decrease Nevada's large market reliance and does so in a manner that provides price stability.

The Preferred Plan uses the approved load forecast from the 2021 Joint IRP, addresses changes in both state and federal carbon policy and fuel and purchase power prices, meets or exceeds the renewable portfolio standard ("RPS") in every year, achieves the state's 2050 clean energy goal,[1] and meets the 16 percent PRM for each utility. While the Preferred and Alternate Plans are very similar, the Companies selected the Preferred Plan as it is more cost-effective and most closely aligned with Nevada's energy policy. NV Energy respectfully requests that the Public Utilities

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[1] The Commission, in requiring the Companies to report on this goal in Docket No. 19-06010, coined the phrase "net-zero carbon emissions goal." In light of growing national and international use of the phrase "net-zero carbon" to refer to a different type of goal that balances remaining carbon emissions with carbon uptake, the Companies are using in this filing the phrase "clean energy goal" to describe the state's 2050 goal. This is consistent with the goal's focus on clean energy production rather than emissions per se.

Commission of Nevada ("Commission") accept the Preferred Plan as described in Section 2 and the application's prayer for relief, and authorize NV Energy to take all necessary steps in the Action Plan period to implement the plan.

This Amendment builds on the advances in recent filings and addresses emerging concerns to ensure reliable and reasonably priced electric service can be delivered to customers through prudent and practical long-term planning. The Amendment addresses:

1. Growing concerns about the availability and deliverability of regional market capacity and energy;
2. Optimized operation of existing generation resources through cost-effective upgrades for customer-focused price stability; and
3. Continued investment in Nevada's emerging clean energy economy, advancing the state's objectives to become a leading producer and consumer of renewable energy while providing more stable rates for retail customers of electric service.

1. The Amendment meets the immediate need to address growing concerns about the availability and deliverability of regional market capacity and energy

As noted in the 2021 Joint IRP, climate change is impacting the western energy markets, requiring the Companies and stakeholders to reevaluate established practices, in particular large reliance on market purchases, 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 ELCC and PRM, and to address changes in weather through the use of new trended weather load forecasts, the focus continues to be on the uncertain availability and deliverability of market capacity and energy.

The 2021 Western Assessment of Resource Adequacy, published by the Western Electric Coordinating Council ("WECC") on February 1, 2022, identifies changes on the western system "affecting how and when entities can rely on imports" and urges entities to act now. WECC identifies concerns in all subregions by 2025 and goes on to say:

> …more frequent extreme weather and a changing climate are… causing concern that imports may not be available when needed. For example, planners and operators can no longer assume that more temperate areas like the Pacific Northwest will be able to provide power to hotter areas like California and the Desert Southwest at any given time.[2]

[2]WECC, 2021 Western Assessment of Resource Adequacy at 7, available at www.wecc.org/Administrative/WARA%202021.pdf.

The WECC assessment further states:

> In addition to being less predictable and more wide-spread, extreme weather events and weather-related events like wildfires are becoming more severe in magnitude and duration. This is stressing the system in ways never experienced and resulting in energy shortages, as capacity is used to support native load or output is reduced due to extreme weather.[3]

NV Energy experienced such an event on July 9, 2021, shortly after the 2021 Joint IRP was filed. On this date, 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[4] 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.

Weather has grown more extreme and resource variability has increased throughout the West. Over the past two summers, continued drought conditions have led to supply reductions from numerous hydroelectric power plants. For the West region, the 2021 water year (October 2020 – September 2021) ranked as the fourth driest water year on record. Temperatures throughout the West also continued to reach record high levels in 2021. The extreme heat combined with drought conditions led to record wildfire activity.

These concerns are compounded by the California Independent System Operator's ("CAISO") change in day-ahead export priorities and Wheel-Through Initiative, both implemented in the summer of 2021, and its more recent revised resource sufficiency test. The first item allows CAISO to adjust day-ahead export schedules to zero with potentially less than an hour's notice to exporters on whether the energy will flow. The second item allows 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 recently 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 has not issued even a Straw Proposal as yet. 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." Regarding the third item, failure to pass the revised resource sufficiency test precludes an entity participating in the Energy Imbalance Market ("EIM") from receiving additional imports, requiring bilateral agreements instead, despite the fact that the EIM continues to expand and is expected to represent 79 percent of the WECC demand by 2023.

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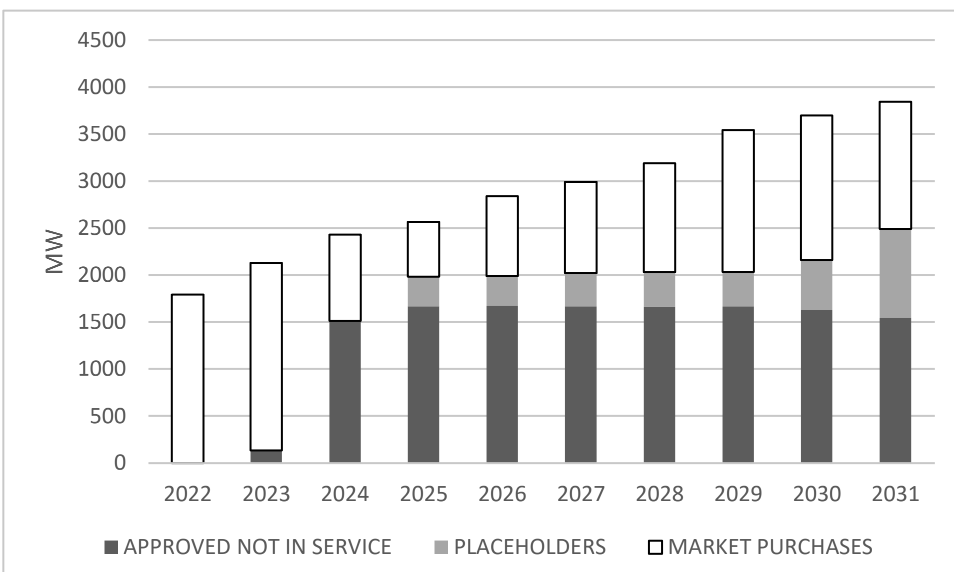
[3] *Id*. at 14.

[4] *See* Docket No. 22-03001, March 1, 2022, Direct Testimony of Ryan Atkins at Q&A 25.

In addition, many fossil and other baseload power plant retirements have recently occurred or are scheduled in the near term West-wide. 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.[5] 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.[6] These changes could dramatically affect the resource mix in the region and the availability of market capacity.

Clearly, cause exists, confirmed by WECC as the reliability regulator in the West, to doubt the availability and deliverability of regional market capacity and energy and, therefore, to limit the Companies' reliance on it on a going-forward basis. This Amendment adds resources to reduce reliance on market capacity in the near term, better positioning NV Energy for changing regional conditions due to climate change and increasing decarbonization in the West. The following figures present the near term uncertainty in the Companies' capacity position in this Amendment relative to the Preferred Plan approved in the 2021 Joint IRP, demonstrating the Amendments' reduced reliance on uncertain market capacity.

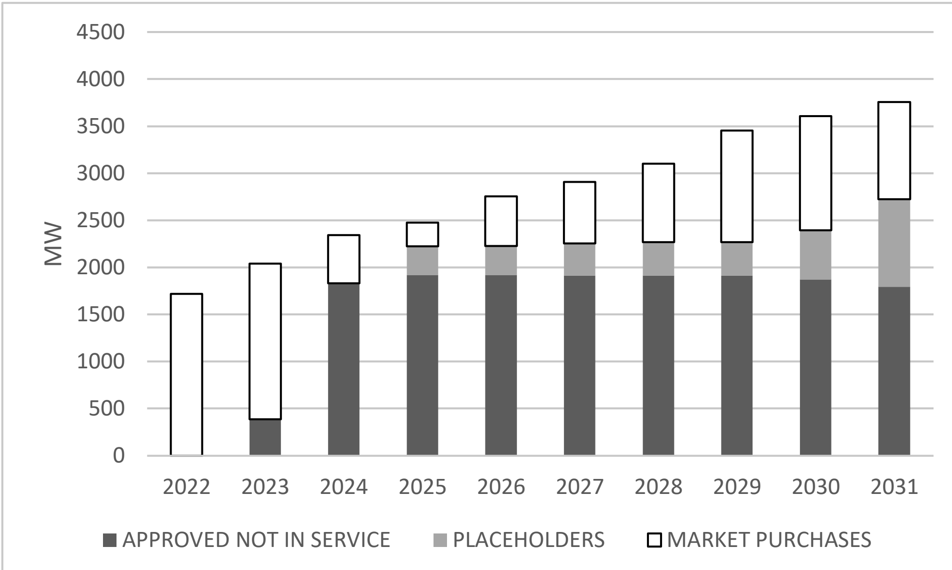
FIGURE I-1
POTENTIAL UNCERTAINTY IN NV ENERGY'S CAPACITY POSITION
2021 JOINT IRP PREFERRED PLAN



[5] *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.

[6] *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.

FIGURE I-2
POTENTIAL UNCERTAINTY IN NV ENERGY'S CAPACITY POSITION
FIRST AMENDMENT PREFERRED PLAN



2. ***In addressing the primary concern regarding the availability of market capacity, the Amendment optimizes operation of existing generation resources through cost-effective upgrades for customer-focused price stability.***

The Amendment proposes multiple projects on existing combustion turbines that will allow the NV Energy system to benefit from a reduction of the open position – reducing reliance on an uncertain market. The projects will also provide increased operational flexibility as additional renewable projects go into service. The proposed upgrade projects target eight existing units and vary in nature, with each project uniquely suited to the affected unit. For example, thermal energy storage is proposed to be added to the existing chillers at the Chuck Lenzie Generating Station, effectively shifting the chiller auxiliary load away from the critical summer peak and evening hours. This beneficial load shifting, like the other proposed upgrades, will cost-effectively reduce the Companies' reliance on market capacity.

3. ***In addressing the primary concern regarding the availability of market capacity, the Amendment continues investment in Nevada's emerging clean energy economy, advancing the State's objectives to become a leading producer and consumer of renewable energy while providing more stable rates for retail customers of electric service***

Energy markets continue to evolve. Across the country, stakeholders – i.e., policy makers, customers and advocacy organizations – continue to press electric service providers to reduce carbon emissions and increase the use of renewable energy. Nevada's state policy is moving in sync with national decarbonizing trends. The Companies fully support the State of Nevada's goals and continue to put forth plans that achieve these goals, while also ensuring resource adequacy and reliability. Both of the plans put forth in this Amendment meet the state's 2050 clean energy goal signed into law in 2019 in Senate Bill 358.

The Companies reviewed a number of resources when building the Preferred and Alternate Plans. Timing in reduction of the open position was a driving factor in the selection of resources to bring forward. The Preferred Plan proposes two diverse renewable projects that target reduced reliance on market capacity as early as summer 2023.

The Companies are pursuing more diverse solutions for energy storage, including the initial benefit of shorter duration storage in the form of 2-hour BESS as proposed in the Preferred Plan and discussed in the Renewables section. In addition, longer duration storage is being investigated in the form of pumped storage hydro.

In conclusion, it is important to note that the Amendment is not driven by a single planning need. Long-term resource and transmission planning decisions are not binary and must be designed to balance multiple objectives in a prudent and practical manner. The long-term obligations incorporated into the Preferred Plan enhance reliability, reduce risk, improve price stability through fixed pricing, increase the diversity of the Companies' supply-side portfolio and meet the state's goals and policies.

SECTION 2. SUMMARY OF SPECIFIC APPROVALS REQUESTED AND CHANGES IN ASSUMPTIONS OR DATA SINCE THE 2021 JOINT IRP

Nevada Administrative Code ("NAC") § 704.9516(1)(a) requires that an amendment to an Action Plan include a section that identifies the items for which the applicant is requesting specific approval. In compliance with this provision of the IRP regulations, Sierra and Nevada Power are making the following specific requests for approval.

1. Approval of the First Amendment to the 2021 Joint IRP base long-term fuel and purchase power price forecasts provided in Technical Appendix FPP-1 as presenting the most accurate information upon which to base the planning decisions set forth in the filing.

2. Approval of the Companies' Preferred Plan, including the resources listed below.[7]
    a. Approval of the Companies' request to amend their Supply-Side Action Plan to add 220 MW of 2-hour, 440 megawatt-hour ("MWh"), lithium-ion battery energy storage at the site of the former Reid Gardner Generating Station. Commercial operation is expected by May 31, 2023, at a cost of

[7] At the time this filing was being modeled and completed, the Companies included wet compression upgrades to the Sun Peak units as part of their Preferred Plan. During this time, the Companies believed that the updates required additional time to install due to modifications to the air permit's current heat input limits based on the current design capability of the existing units. However, since that time, the Companies identified an option to install the wet compression on the Sun Peak units prior to summer 2022 and continue to operate under the existing permit heat input requirements. This option will provide additional capacity during the summer 2022 peak, which as described above is an important issue to address in this filing. As a result, although the Sun Peak upgrades are included in the modeling of the Preferred Plan, the Companies are not requesting approval of the upgrades in this filing.

$217 million and will be owned by Nevada Power. The price of the 2-hour battery is tied to the price of lithium and is thus subject to a price adjustment according to a lithium index price change up or down.[8]

b. Approval of the Companies' request to amend their Supply-Side Action Plan to allow Sierra to enter into the North Valley PPA for 25 MW (net) of geothermal generation. Commercial operation is expected in December 2022, with a 25-year term at a flat energy price of [redacted] per MWh.[9]

c. Approval of the Companies' request to amend their Supply Side Plan to expend approximately $6 million to install a peak firing project on the Tracy Generating Station Units 8 and 9, increasing the station's total peak capacity by approximately 12 MW with an in-service date of May 2024.

d. Approval of the Companies' request to amend their Supply Side Plan to expend approximately $12 million to install a peak firing project on the Chuck Lenzie Generating Station Units 1 through 4, increasing the station's total peak capacity by approximately 24 MW with an in-service date of May 2024.

e. Approval of the Companies' request to amend their Supply Side Plan to expend approximately $6 million to install a peak firing project on the Harry Allen Generating Station Units 5 and 6, increasing the station's total peak capacity by approximately 12 MW with an in-service date of May 2024.

f. Approval of the Companies' request to amend their Supply Side Plan to expend approximately $13 million to install a thermal energy storage project at the Chuck Lenzie Generating Station, increasing the station's peak capacity by approximately 18 MW with an in-service date of May 2024.

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[8] Negotiations with Tesla were ongoing as of the date of this filing to finish the detailed scope, schedule, and contract price adjustment for Lithium index pricing. Due to the price volatility of the Lithium Carbonate used in the battery system, the EPC contract will include an index adjustment method from a baseline. The baseline index price, upon which the $217 million estimate is based, was established in November 2021. Since November, the index has increased. Using the March 3, 2022, spot price for the Lithium Carbonate index would result in a BESS equipment cost increase of $17.5 million. A maximum for the index price is approximately five times the baseline index price of Lithium Carbonate, or approximately $50 million (which includes the current currency rate adjustment). If the maximum is reached this will trigger a 30-day period to negotiate an agreement. If an agreement between the parties is not reached, the Companies will have a termination payment of 10 percent of the Tesla battery value plus direct EPC costs. In exchange the Companies would receive batteries equal to 10 percent of the adjusted value of the Tesla batteries as shown in REN-6 - Reid Gardner BESS Cost Estimate (Confidential). The converse also applies: should the Lithium Carbonate index pricing be lower than the baseline, a negative adjustment would be applied to the equipment pricing.

[9] The PPA is competitively priced and represents one of the best values the Companies have been able to receive for a geothermal resource. The project's developer is currently in negotiations with a number of out-of-state load-serving entities for its other geothermal resources. Disclosure of the North Valley PPA pricing information will undermine the developer's negotiating position with those other entities which will in turn create a disincentive for the developer to enter into competitively priced PPAs with the Companies in the future. Such a disincentive will negatively affect the Companies' ability to negotiate the best terms and secure diverse renewable resources for their customers.

g. Approval of the Companies' request to amend their Transmission Plan to expend approximately $2.5 million to construct network upgrades needed to support the interconnection of the 220 MW 2-hour BESS at the Reid Gardner Substation.

3. Approval of $3.5 million to support the developer's continued development and perform the Companies' due diligence on a pumped storage hydro project located in White Pine County. In addition, this expenditure secures the Companies' exclusive right to acquire the project.

NAC § 704.9516(1)(b) requires that an amendment to an Action Plan include a section that "specifies any changes in assumptions or data that have occurred since the utility's last resource plan was filed." As state above, the Preferred Plan uses the approved load forecast from the 2021 Joint IRP, addresses changes in both federal carbon policy and fuel and purchase power prices, meets or exceeds RPS in every year, achieves the state's 2050 clean energy goal, and meets the 16 percent PRM for each utility. The Updates to Key Modeling Assumptions subsection of the Economic Analysis Section, Section 8 of the narrative, lists the key modeling assumptions and updates to those assumptions. Within the Common Methodologies and Assumptions subsection of the Financial Plan, the assumed marginal cost of new long-term debt is the only assumption that changed. This modeling assumption now bases the Financial Plan on the long-term debt cost of 2.95 percent to 4.27 percent, up from the 2.45 percent to 3.21 percent range in the 2021 Joint IRP.

SECTION 3. LOAD FORECAST

The load forecast for the First Amendment to the 2021 Joint IRP is identical to the load forecast that was filed and approved by the Commission in Docket No. 21-06001, the 2021 Joint IRP. This load forecast covers calendar years 2022 through 2041.

Load Forecast Summary: Consistent with NAC § 704.923(2) and NAC § 704.9516(e), Table LF-1 is a summary of the forecasted peak loads and energy consumption from 2021 through 2041. It is important to note that NV Energy peak demands may be lower than the combined total of Sierra and Nevada Power due to diversity between the two systems. *i.e.*, they do not necessarily peak at the same time.

TABLE LF-1
NATIVE ENERGY (GWH) AND ANNUAL PEAK (MW)

	Native Energy (GWh)			Peak (MW)		
Year	NVE	NPC	Sierra	NVE	NPC	Sierra
2021	31,267	20,793	10,474	7,763	5,880	1,923
2022	31,070	21,382	9,688	7,715	5,949	1,801
2023	31,819	21,874	9,945	7,843	6,038	1,840
2024	32,536	22,236	10,299	7,947	6,125	1,876
2025	32,859	22,308	10,551	7,999	6,127	1,913
2026	32,602	22,423	10,179	7,994	6,160	1,876
2027	33,104	22,690	10,415	8,106	6,243	1,902
2028	33,523	22,860	10,664	8,217	6,314	1,939
2029	33,815	22,975	10,840	8,225	6,337	1,961
2030	33,958	23,074	10,884	8,287	6,372	1,964
2031	34,117	23,214	10,903	8,350	6,410	1,972
2032	34,327	23,403	10,924	8,398	6,460	1,972
2033	34,477	23,535	10,942	8,457	6,504	1,979
2034	34,649	23,687	10,962	8,535	6,574	1,988
2035	34,830	23,843	10,987	8,518	6,590	1,993
2036	35,058	24,041	11,017	8,598	6,620	2,004
2037	35,207	24,165	11,042	8,648	6,663	2,016
2038	35,387	24,317	11,071	8,689	6,698	2,021
2039	35,567	24,465	11,101	8,764	6,758	2,033
2040	35,773	24,640	11,132	8,771	6,793	2,041
2041	35,906	24,749	11,157	8,852	6,844	2,047
CAGR						
22-31	1.0%	0.9%	1.3%	0.8%	0.8%	0.9%
32-41	0.5%	0.6%	0.2%	0.5%	0.6%	0.4%

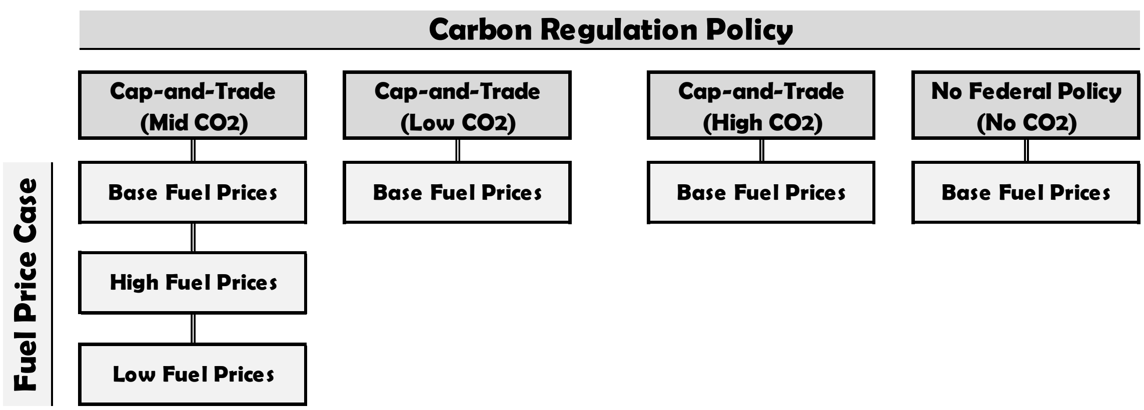
Notes:
(1) NVE Peak adjusted for diversity.
(2) Hourly value of Company coincident peak

SECTION 4. FUEL AND PURCHASED POWER PRICE FORECASTS

The Companies have updated fuel and purchased power forecasts for two main reasons: (1) higher observed power, coal and natural gas market quotes used in the short-term forecast; and (2) release of the new long-term outlook ("LTO") by Wood Mackenzie ("WoodMac"), the provider of the fundamental power and natural gas price forecast.

Forecasts of fuel and purchased power prices are essential inputs to an IRP analysis. Robust production cost analysis conducted using PROMOD tests the sensitivity of results against different fuel and purchased price assumptions. The Companies have developed sensitivity studies around low, base and high fuel prices, together with low, base and high purchased power prices, including and excluding the impacts of carbon regulation. A total of six separate price forecast scenarios were developed to determine the impacts of both carbon regulation policy and fuel price levels on production costs and resource options. Three price forecast scenarios—base, high and low fuel prices—were prepared. These forecast scenarios were used in preparing the analysis presented in this Amendment. Also, three alternative cases were prepared assuming base fuel prices but imposing various levels of carbon pricing (low CO_2, mid CO_2 and high CO_2). All six cases are shown in Figure PF-1.

FIGURE PF-1
PRICE FORECAST SENSITIVITY SCENARIOS



The methodology used to prepare the base case forecasts for power and natural gas prices relies upon observable market quotes in the near-term forecast years, which are gradually blended into long-term price forecasts obtained from an external consulting firm specializing in market fundamentals and fundamental price forecasting. The price forecast curves for power, natural gas, and coal are important to the economic evaluation of alternative electric resource plans. For example, higher natural gas prices, which are a variable expense in operating fossil fuel-fired plants, can increase the attractiveness of renewable energy options, which have no variable operating fuel expense, but potentially higher up-front plant investment costs to construct on a dollars per kW basis.

Market quotes used for short-term forecast. Market quotes consist of observed trades in the relevant trading hubs: for natural gas, the Henry Hub, Alberta NOVA Inventory Transfer ("AB-NIT" or "AECO"), Sumas, Northwest Pipeline Rockies ("Rockies"), Malin, San Juan, Northwest Pipeline Rockies ("Rockies"); and for power, the Mid-Columbia ("Mid-C") hub and the Mead trading hub. The source of market quotes is Argus Media ("Argus") for natural gas prices and for western regional power prices. The market quotes for the IRP forecast were prepared as an average of settlement prices for a 21-day trading period from November 1, 2021, through November 30, 2021.

Fundamental (long-term) forecast. The fundamental forecasts of power and natural gas prices are provided through a subscription service with WoodMac, a global energy, metals and mining and consultancy service. WoodMac maintains an international reputation for supplying comprehensive data, written analysis and consultancy advice. The Companies perform detailed fundamental modeling of regional electric and natural gas systems, taking into account structural supply-demand price dynamics. For internal consistency, WoodMac's projections of natural gas and power prices are taken from a single integrated forecast, the LTO - Policy Headwinds (no carbon case), released October 12, 2021.

A. Base Gas Price Forecast

The monthly gas price forecast by regional hub begins with the 21-day average of market quotes in November of 2021 for the near-term forecast months, January 2022 through March 2025. For the intermediate-term months, April 2025 through March 2027, a blending process is used to gradually transition from the 21-day average quotes to the long-term fundamental natural gas price forecast from WoodMac.[10] The long-term fundamental forecast is used exclusively from April 2027 through December 2051. The Base Fuel-Mid CO_2 annual natural gas price forecast for the Rockies, Malin, AECO and SoCal hubs is shown in Figure PF-2.

[10] Blending of market quotes and the fundamental forecast occurs across four gas seasons, or 24 months (April 2025 through March 2027), with a weighting of the fundamental forecast increasing by 4 percent per month.

FIGURE PF-2 [CONFIDENTIAL]
ANNUAL AVERAGE GAS PRICE FORECAST
(BASE FUEL-MID CO_2)

[redacted]

The associated monthly prices and additional trading hubs are provided in Technical Appendix FPP-1.

B. Base Market Implied Heat Rate Forecast

The economic evaluation of generation alternatives in this IRP Amendment is based on a production cost software model that dispatches the Companies' portfolio of generation and contracted resources (subject to unit operating constraints) against an economic opportunity to purchase power in the regional market at wholesale market prices. An essential input to this analysis is the wholesale power price forecast, which is prepared by multiplying the gas price forecast described above and a forecast of market implied heat rates ("MIHR") at nearby trading hubs for both on-peak and off-peak periods. The multiplication of monthly gas prices (in dollars per MMBtu) with monthly on-peak and off-peak MIHR (in metric million British thermal unit ("Btu") per MWh) yields a monthly forecast of on-peak and off-peak power prices (in dollars per MWh).

Consistent with the approach used in prior IRPs and IRP amendments, the first part of the MIHR curve, through March 2025, is derived using the ratio of the 21-day average power price quotes and the 21-day average forward gas prices. The second part of the curve, from April 2025 to March 2027, reflects a blend of heat rates based on market quotes and heat rates based on the fundamental forecast. In the blending process, pure quotes receive more weighting in the initial months of the forecast blending period, while the fundamental-based heat rates receive more weighting towards the end of the 24-month blending period. The third part of the curve, from April 2027 through December 2051, is derived entirely from the fundamental-based curve from WoodMac. Figure PF-3 and Figure PF-4 provide the base case forecast (Base Fuel-Mid CO_2) of average MIHRs for delivered energy to southern and northern Nevada these MIHRs are also provided on a monthly basis in Technical Appendix FPP-1.

FIGURE PF-3 [CONFIDENTIAL]
AVERAGE MARKET IMPLIED HEAT RATE FORECAST – SOUTHERN NEVADA
(BASE FUEL-MID CO_2)

[redacted]

FIGURE PF-4 [CONFIDENTIAL]
AVERAGE MARKET IMPLIED HEAT RATE FORECAST – NORTHERN NEVADA
(BASE FUEL-MID CO_2)

[redacted]

C. Base Power Price Forecast

Once the forecast of MIHR is prepared, the hub power prices can be computed as the product of the MIHR (on-peak and off-peak periods) and the corresponding hub gas prices. For example, the Mid-C power price forecast was derived by multiplying the natural gas price forecast at Sumas by the forecast of MIHR at Mid-C and the Mead power price forecast was derived by multiplying the natural gas price forecast at SoCal by the forecast of MIHR at Mead.

The forecast of monthly power prices averaged annually for Mead are presented in the Figure PF-5. The forecast of monthly power prices averaged annually for northern Nevada are presented in the Figure PF-6. As illustrated on the charts, PF-5 and PF-6, the forecasted power price declines from the historic highs in the near term, stabilizes in the mid-term and continues to grow gradually in the long term. The power price sharp decrease in the near term is caused by observed declining market quotes.

FIGURE PF-5 [CONFIDENTIAL**]**
AVERAGE ANNUAL POWER PRICE FORECAST – MEAD
(BASE FUEL-MID CO_2)

[redacted]

FIGURE PF-6 [CONFIDENTIAL]
AVERAGE ANNUAL POWER PRICE FORECAST – NORTHERN NEVADA
(BASE FUEL-MID CO_2)

[redacted]

The monthly on-peak and off-peak prices for the various carbon cases are included in Technical Appendix FPP-1, respectively.

D. High and Low Gas Price Forecasts

High and low gas prices. The Companies also prepared high and low sensitivities around the base case market price forecasts. An assumption of plus-and-minus one standard deviation around the base gas price forecast was computed for the high and low cases. Market quotes of implied volatilities from at-the-money call options from November 2021 were used to calculate the volatility of natural gas futures for the period from January 2023 to November 2024. Henry Hub volatility of 22 percent was used from December 2024 for remainder of the forecast period. These volatilities were used to calculate the high and low natural gas prices.

The base, high and low-price projections for SoCal natural gas and Malin natural gas that result from applying the volatility curve are illustrated in Figures PF-7 and PF-8.

FIGURE PF-7 [CONFIDENTIAL]
BASE, HIGH AND LOW GAS PRICE FORECAST – SOCAL

[redacted]

FIGURE PF-8 [CONFIDENTIAL]
BASE, HIGH AND LOW GAS PRICE FORECAST – MALIN

[redacted]

E. High and Low Power Prices

Once the high and low gas price trajectories are computed, the Companies adjust the base case power price forecasts for Mead and northern Nevada delivered power. For on-peak and off-peak periods, the high and low power prices are calculated by first multiplying the high and low gas prices with a heat rate of 7,000 Btu/kWh.[11] The product of this calculation is added to the monthly spark spreads from the base case price forecast.[12] This methodology provides a reasonable estimate for market prices where natural gas-fired generation is setting market clearing prices, such as in Nevada.

[11] 7,000 Btu/kWh heat rate represents efficiency of a standard natural gas combined-cycle power generator.

[12] Note that the high and low power price forecast cases incorporate market variability around fuel prices only (*i.e.,* these sensitivity forecasts hold constant the spark spread embedded in the base case forecast). The spark spread is the difference between the price received by a generator for electricity produced and the cost of the natural gas used to produce that electricity; it is also an estimation of the value of energy in wholesale markets, reflective of the comparative balance between power supplies and electricity demand.

The average annual base, high and low on-peak power prices for southern Nevada (Mead trading hub) are graphed in Figure PF-9. The average annual base, high and low on-peak power prices for northern Nevada are graphed in Figure PF-10.

FIGURE PF-9 [CONFIDENTIAL]
BASE, HIGH, LOW POWER PRICE FORECAST - MEAD (ON-PEAK)

[redacted]

FIGURE PF-10 [CONFIDENTIAL]
BASE, HIGH, LOW POWER PRICE FORECAST – NORTHERN NEVADA (ON-PEAK)

[redacted]

F. Capacity Price Forecast for Market Purchases

The Companies have included a long-term capacity price forecast to supplement the regional power price forecast from WoodMac. The regional price forecast is used as an input to PROMOD for determining economic dispatch of market purchases against internal generation, the capacity price forecast (dollars per kW-year) is incorporated in the production cost assessment as a fixed cost to estimate the total costs associated with the Companies' open capacity position.

WoodMac's regional power price forecast represents spot firm energy prices; however, the energy prices do not include the full cost of new capacity that would be required to ensure resource adequacy over the forecast period. To ensure resource adequacy across the forecast horizon, WoodMac develops estimates of the levelized cost of new entry ("CONE") for combined cycle and combustion turbine generation throughout WECC. 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) and is used to compute the long-term capacity price forecast. WoodMac calculates the annual capacity prices (in dollars per kW-year) based on the net CONE, or the levelized cost of new entry net of the revenues from energy and ancillary services.

In preparation of this Amendment, the Companies incorporated a blend of WoodMac's capacity price forecasts for Northwest Power Pool ("NWPP"), Southwest Reserve Sharing Group ("SRSG") and California to approximate the mix of purchased power. The increase in projected capacity prices, as presented in Figure PF-11, is caused by unit retirements and more expensive firm capacity additions, in particular, battery storage.

FIGURE PF-11
PROJECTED CAPACITY PRICES [CONFIDENTIAL]

[redacted]

The capacity values serve as a proxy for the potential cost associated with carrying open positions (*i.e.,* until the positions are closed with firm products). The capacity adder is representative of potential additional costs that may be incurred, either in short-term power markets subject to price spikes under deficit market conditions, or as a proxy for the fixed costs of another new or existing power resource.

G. Coal Price Forecast

The price of coal delivered to the Companies' coal-fired generating units at the North Valmy generating station was forecasted based upon the following methodology.

Market-indicative coal forecasts produced by S&P Global Market Intelligence represent forward curves for spot-traded instruments, analogous to a strip of contracts, with the shorter tenors — current year, prompt year, plus additional years if available — driven by the observed/assessed market and the longer tenors — typically years three through 20 for physically assessed markers and NYMEX futures — driven by fundamental estimates of cash costs of production, accepted returns to capital, regional productive capacity, and forecast supply and demand. For the long-tenured portion of the curve, S&P Global Market Intelligence forecasts prices for specific coal markers and defines the remaining markers via historical spreads. Forecasted base, high, and low coal prices delivered to North Valmy in dollars per unit of heat content ($/MMBtu) are developed and are shown below in Figure PF-12.

FIGURE PF-12
PROJECTED COAL PRICES [CONFIDENTIAL]

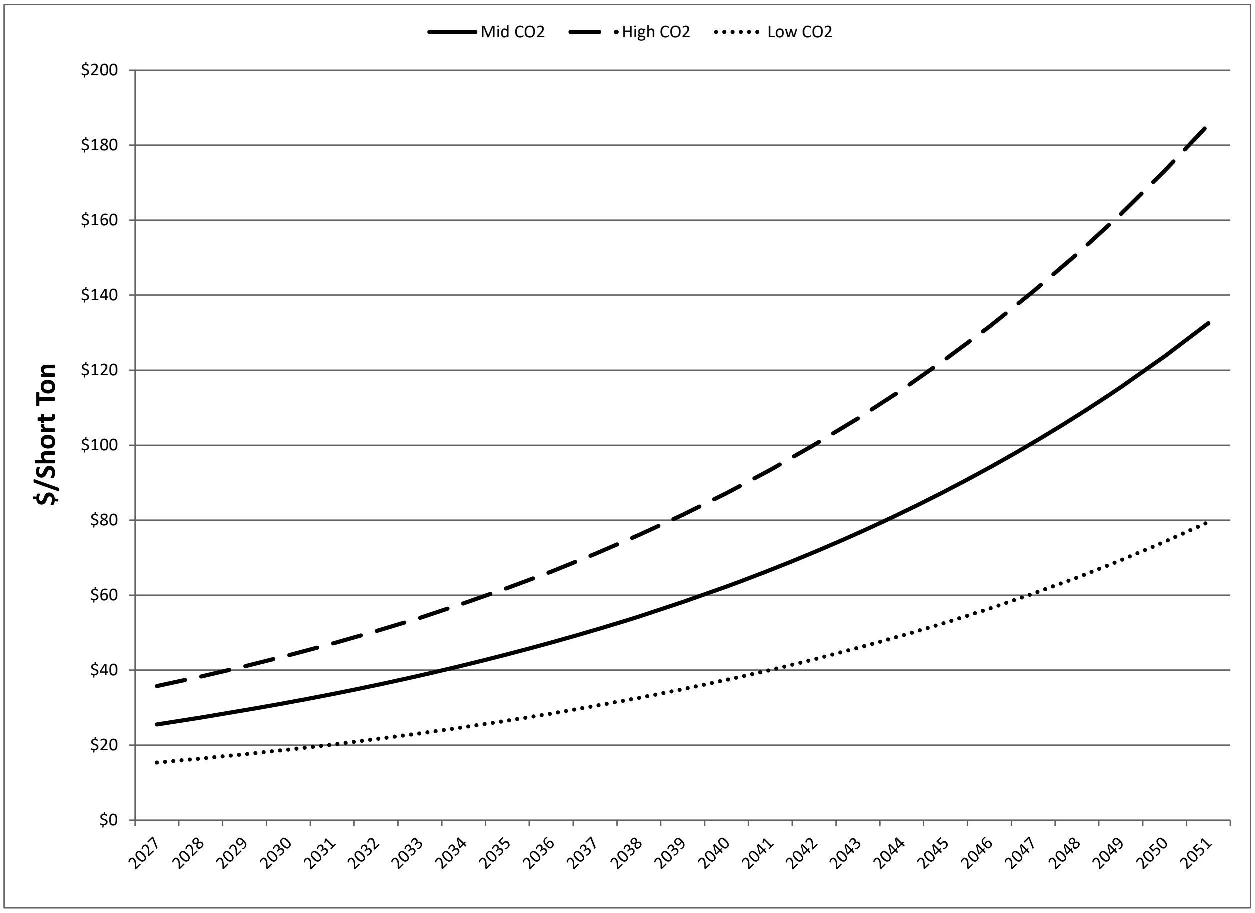
[redacted]

H. Price Forecast and Modeling of Potential Carbon Costs

The Companies prepared price forecasts to evaluate the production cost impacts of potential future greenhouse gas ("GHG") regulations under federal cap-and-trade pricing regimes that would commence in 2027. A separate base forecast was prepared that assumes no federal *or* Nevada specific GHG regulations are implemented. The Companies' base planning assumption is the mid-carbon price forecast scenario using base fuel prices to assess the potential increases in total fuel and purchased power costs. Low- and high-carbon price forecasts were also prepared for the base fuel forecast.

No carbon case. The Companies prepared a no-carbon forecast, assuming base fuel and purchased power prices, which does not include any costs associated with future federal GHG regulations. In its Long-Term Outlook regional modeling of the WECC power markets, published on October 12, 2021 ("Policy Headwinds"), WoodMac assumes no federal CO_2 mandated carbon regulation. The carbon allowance prices under the alternative CO_2 scenarios are shown in Figure PF-13.

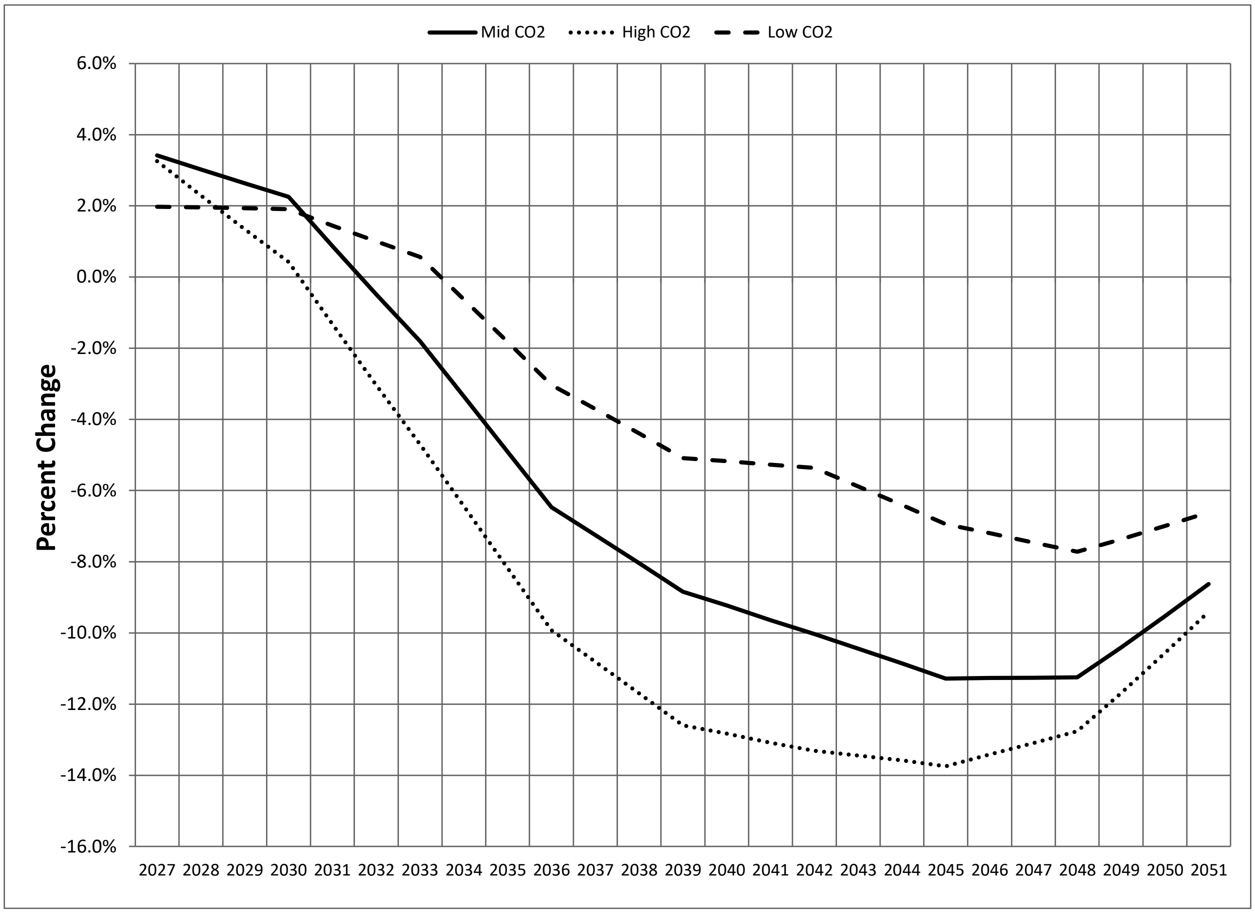
FIGURE PF-13
CARBON ALLOWANCE PRICES



A more detailed description of potential future GHG regulations and estimations of carbon allowance prices for the various scenarios are provided in the direct testimony of Dr. David Harrison and the Economic and Environmental Benefit Study prepared by NERA Economic Consulting ("NERA"), Technical Appendix ECON-9, herein referred to as "NERA Report."

Fuel price impacts from carbon. The production cost impacts of the six future carbon regulation scenarios (Figure PF-1) were then evaluated using PROMOD. To develop inputs for those evaluations, NERA estimated how the future carbon scenarios could change the total consumer demand for fossil fuels and, thereby, impact the price levels for various fossil fuels that affect the cost of electricity in Nevada. NERA estimated the price impacts to natural gas and coal fuels, due to changes in demand for these fuels, using a proprietary energy model - the NewEra model. This model is a unique tool for effectively measuring the macroeconomic and detailed sectorial impacts of changes affecting the energy sectors. The Companies applied these price impacts (adjustors) to the no-carbon case fuel price forecasts for use in the PROMOD generation dispatch model. The percentage adjustors to natural gas prices under the carbon cases are illustrated in Figure PF-14.

FIGURE PF-14
NATURAL GAS PRICE ADJUSTMENTS FOR CARBON SCENARIOS
(HENRY HUB)

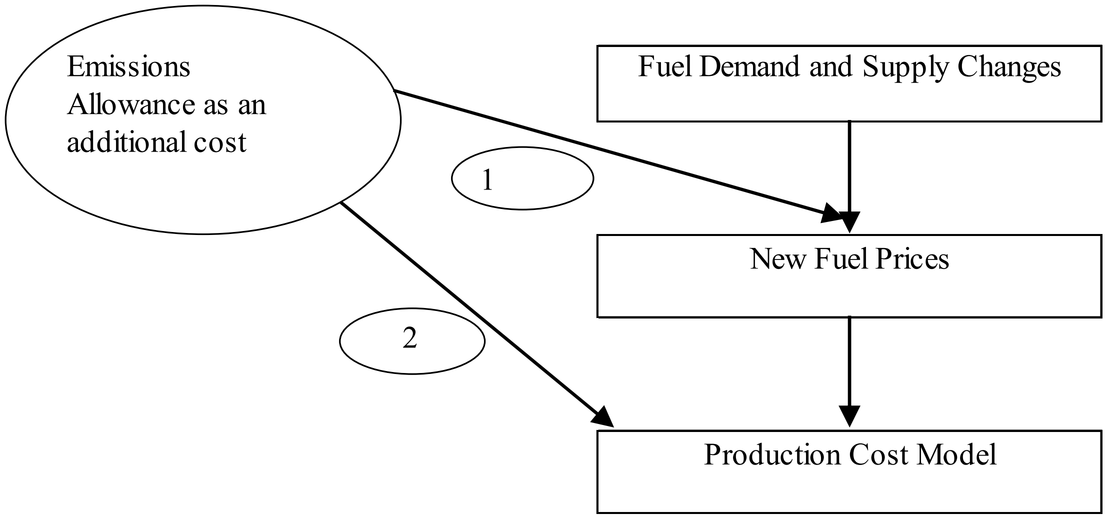


These price impacts were applied to the no-carbon natural gas price forecast from WoodMac to create natural gas price forecasts under carbon scenarios. As noted in the NERA Report, these gas price adjustments do not include the costs of CO_2 allowances shown above in Figure PF-13; the full cost of burning natural gas in electric power plants includes the cost of CO_2 allowances, which are instead included in the PROMOD modeling as a variable power production cost.

As noted in the NERA Report, the future price impacts to fossil fuels resulting from future GHG and related regulations are highly uncertain. Price impacts are subject to a range of uncertainties, including both electricity production and consumption.

Power price impacts from carbon. Estimating the effects of GHG regulation on power prices requires modeling the effects on fuel prices and on the cost of burning fossil fuels. The Companies modified the fuel price forecasts for expected changes in fuel demand and used these adjusted prices as inputs to PROMOD. The cost of carbon emissions was modeled in the variable power dispatch cost in the PROMOD modeling. This process is illustrated in Figure PF-15.

FIGURE PF-15
EXAMPLES OF MODELING POWER PRICE IMPACTS FROM CARBON



Next, the Companies estimate the effects on wholesale regional power of carbon allowance prices plotted in Figure PF-13. The Companies model the carbon allowance prices as being endogenous to the wholesale power market. Thus, the price of market purchases is consistently evaluated in the PROMOD economic dispatch algorithm with the Companies' own estimated costs to generate, which includes the carbon allowance prices as a variable cost based upon the emission characteristics of the Companies' generators.

As an introduction, Figure PF-16 provides an example of the computation of carbon costs to gas and generating units.

FIGURE PF-16
EXAMPLE CARBON COSTS TO POWER PRICES
($ per MWh)

	A	B	C	D	E=A*B*C/D
Unit Type	CO_2 Emission Factor (lb CO_2/MMBtu)	Plant Heat Rate (MMBtu/MWh)	Carbon Price ($/Short Ton)	Conversion (lb/short ton)	Carbon Cost ($/MWh)
Natural Gas	116.65	7.000	20.00	2,000	8.17

The formula in the rightmost column of the Figure PF-16, above, shows that the $/MWh potential increase in power prices for carbon costs is the product of three factors: the CO_2 emission factor for fuel type, the individual plant's heat rate, and the carbon allowance price.

To prepare estimates of how varying carbon allowance prices (as illustrated in Figure PF-13) could impact wholesale market prices for purchase power, the Companies incorporated price adders consistent with a 7,000 Btu/kWh natural gas-fired generator as illustrated in Figure PF-16. The Companies incorporated the power price adders to the base, high and low fuel price forecast scenarios to derive the new power price forecasts under the mid, high and low carbon scenarios.
Finally, the power price forecasts under the carbon scenarios incorporated the net effect from the adjustments to underlying gas prices for carbon (due to supply/demand considerations) and the carbon costs (refer to Figure PF-14).

SECTION 5. AMENDMENTS TO SUPPLY SIDE PLAN - GENERATION

A. Existing Generation

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

- Brunswick Diesel Plant – Sierra: A six MW peaking plant, comprised of three reciprocating diesel-fired engines located on approximately 10 acres in Carson City, Nevada. This plant is operational and designated as Sierra's black start capability. The plant is restricted to 50 operating hours and is used for system emergencies and is not included on the L&R tables.

- Chuck Lenzie Generating Station – Nevada Power: 1,142 MW of total peak summer capacity including duct burners and inlet chillers. The plant is located approximately 24 miles northeast of Las Vegas, Nevada, and is composed of two 2x1 natural gas-fired combined-cycle units (591 MW Block 1 and 551 MW Block 2).

- Clark Generating Station – Nevada Power: 1,102 MW of total peak summer capacity, located in Las Vegas, Nevada. Clark Station is composed of two 2x1 natural gas-fired combined-cycle units (430 MW), one natural gas-fired combustion turbine unit (54 MW), and 12 natural gas-fired simple-cycle combustion turbines ("Clark Peakers") (618 MW).

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

- Ft. Churchill Station – Sierra: Two natural gas-fired condensing steam turbine units located 10 miles north of Yerington, Nevada. Total peak summer capacity of these units is 226 MW.

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

- Harry Allen Generating Station – Nevada Power: 628 MW of total peak summer capacity located 24 miles northeast of Las Vegas, Nevada. The Harry Allen Generating Station is comprised of the 484 MW natural gas-fired Harry Allen Combined Cycle facility, as well as 144 MW of natural gas-fired combustion turbine peak summer capacity generated by two gas-fired turbine units (72 MW each).

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

- Nellis Solar PV II – Nevada Power: 15 MW AC capacity, located on the Nellis Air Force Base in North Las Vegas, Nevada. The Nellis PV plant is a single-axis tracker, consisting of ten 1.5 MW blocks. The plant went into service in November of 2015.

- North Valmy Station – Sierra: Sierra owns 50 percent of two coal-fired condensing steam units with a peak summer capacity of 522 MW. Sierra's share of capacity from the two units at Valmy is 261 MW. North Valmy Station is located 19 miles west of Battle Mountain, Nevada.

- Silverhawk Generating Station – Nevada Power: 520 MW of total peak summer capacity, including duct burners, located approximately 26 miles northeast of Las Vegas, Nevada. The plant is comprised of one 2x1 natural gas-fired combined-cycle unit.

- Sun Peak Generating Station – Nevada Power: 210 MW of net summer peak capacity located in Las Vegas, Nevada. Sun Peak Generating Station is comprised of three dual-fuel (natural gas and No. 2 fuel oil) simple-cycle combustion turbine units (each capable of producing 70 MW).

- Tracy Station – Sierra: 753 MW of total peak summer capacity, located approximately 15 miles east of Reno, Nevada. The Tracy Station is comprised of one natural gas-fired steam unit with a total peak summer capacity of 108 MW and two natural gas-fired combined-cycle blocks with a peak summer capacity of 645 MW.

- Walter Higgins Generating Station – Nevada Power: 589 MW of total peak summer capacity including duct burners, located approximately 35 miles southwest of Las Vegas, composed of one 2x1 natural gas-fired combined-cycle unit.

Table GEN-1 summarizes in tabular form Nevada Power's and Sierra's generating units and their respective operating characteristics including name plate ratings, and winter, summer and peak capacities, commercial operation dates, deprecation-based retirement dates and fuel types. More detail and modeling data for the resources are included in Confidential Technical Appendix GEN-1

TABLE GEN-1
GENERATING UNITS SUMMARY

Unit	Commercial Operation Date	Depreciation Based Retirement Date	Prime Mover[13]	Designation	Name Plate (MW)	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Primary Fuel Storage Capacity[14]	Secondary Fuel Storage Capacity
Sierra[15]										
Brunswick	1960	2028	Recip	Peaker	6	6	6	Diesel	44 hrs	0
Clark Mt. 3	1994	*2034*	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Clark Mt. 4	1994	*2034*	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Ft. Churchill 1	1968	*2028*	Steam	Intermediate	105	113	113	Nat Gas	0	0
Ft. Churchill 2	1971	*2028*	Steam	Intermediate	105	113	113	Nat Gas	0	0
Tracy 3	1974	*2028*	Steam	Intermediate	110	108	108	Nat Gas	0	0
Tracy 4&5 (Pinon)	1996	*2031*	CC /Steam	Intermediate	113	108	104	Nat Gas	0	0
Tracy 8, 9, 10	2008	*2043*	CC /Steam	Base	623	578	553	Nat Gas	0	0
Valmy 1	1981	*2021*	Steam	Intermediate	127	127	127	Coal	200 days	200 days
Valmy 2[16]	1985	*2025*	Steam	Intermediate	134	134	134	Coal	200 days	200 days
Nevada Power										
Clark 4	1973	2030	CT	Peaker	60	63	55	Nat Gas	0	0
Clark 5, 6, 7	1979. 1979, 1994	2034	CC /Steam	Intermediate	236	84	73	Nat Gas	0	0
Clark 7, 8, 9	1980, 1982, 1994	2033	CC /Steam	Intermediate	236	84	73	Nat Gas	0	0
Clark 11 - 22	2008	*2038*	CT	Peaker	726	57	52	Nat Gas	0	0
Goodsprings	2010	2040		Base	7.5			Waste Heat	0	0
Harry Allen 3	1995	2035	GT	Peaker	72	84	74	Nat Gas	0	0

[13] "CT" indicates combustion turbine, "CC" indicates combined cycle.
[14] Fuel Storage Capacity assumes full load operation.
[15] Brunswick is not listed on L&R tables because it is a black start/emergency only unit and is not available for normal capacity.
[16] The two Valmy units are 50 percent owned by Idaho Power Company. Figure GEN-1 shows only Sierra's 50 percent share of the capacity of the two Valmy units.

Harry Allen 4	2006	2036	GT	Peaker	72	84	74	Nat Gas	0	0
Harry Allen CC	2011	2046	CC /Steam	Base	558	524	510	Nat Gas	0	0
Chuck Lenzie 1	2006	*2041*	CC /Steam	Intermediate	610	601	585	Nat Gas	0	0
Chuck Lenzie 2	2006	*2041*	CC /Steam	Intermediate	610	601	585	Nat Gas	0	0
Silverhawk CC	2004	*2039*	CC /Steam	Intermediate	599	599	560	Nat Gas	0	0
Walt Higgins CC	2004	*2039*	CC /Steam	Intermediate	688	621	604	Nat Gas	0	0
LV Gen 1	1994	*2029*	CC /Steam	Intermediate	61.3	51	48	Nat Gas	0	0
LV Gen 2	2004	*2039*	CC /Steam	Intermediate	148.8	115	112	Nat Gas	0	0
LV Gen 3	2004	*2039*	CC /Steam	Intermediate	148.8	115	112	Nat Gas	0	0
Sun Peak 3	1991	*2031*	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 4	1991	*2031*	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 5	1991	*2031*	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	180 hours[17]

1. <u>Other Generation Assets</u>

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

- <u>Mohave Generating Station – Nevada Power:</u> The Mohave site is located in Laughlin, Nevada, and is the previous site of a 1,500 MW coal-fired generating plant. The site is co-owned by Southern California Edison ("SCE") (56 percent), Salt River Project ("SRP") (20 percent), Nevada Power (14 percent) and Los Angeles Department of Water and Power (10 percent). SCE is the controlling partner of the facility. Mohave ceased operations on January 1, 2006, and was decommissioned.[18] In 2015, the co-owners agreed to proceed with selling most of the property through a public sale process. The property was listed

[17] No diesel fuel is currently sored on site.

[18] As defined in NRS § 704.7332.

by a nationwide commercial real estate firm in October 2016. No sales transactions have been executed at this time.

- Reid Gardner Generating Station – Nevada Power: The last unit at the Reid Gardner Generating Station ceased operations in March 2017 and the plant is in a state of Post-Operational Reserve and in the process of moving to the state of Decommissioned.[19] The units have been dismantled and demolished and site remediation has begun. A final disposition plan for the site will be developed as the site remediation scope becomes better known.

- Navajo Generating Station – Nevada Power: The Navajo Generating Station is located near Page, Arizona and is a previous site of a 2,250 MW total net capacity coal-fired facility. Nevada Power has undivided ownership rights to 11.3 percent ownership share of the Navajo Generating Station. The coal-fired facility ceased operation in November 2019 and decommissioning and demolition of the generating units has been completed. The Navajo Generating Station includes the generating station, transmission lines and interconnections, water, and rail facilities, and is co-owned by five parties as tenants-in-common, who together with the United States are "Participants" in the Navajo Project. The Participants' relative interests in the non-transmission facilities are as follows:

  - SRP (42.9 percent);
  - U.S. Bureau of Reclamation (24.3 percent), whose share is owned by the SRP;
  - Arizona Public Service (14 percent);
  - Nevada Power (11.3 percent); and
  - Tucson Electric Power (7.5 percent)

The decommissioning and demolition plan was approved by the Commission in Docket No. 15-05004. A final disposition plan for the site has not been determined.

2. New Generation Projects

a. Capacity Upgrade Projects

NV Energy is requesting approval of upgrades to several of its combustion turbines. The proposed combustion turbine upgrades would increase output for a limited number of operating hours during net peak periods. These upgrades will allow the NV Energy system to benefit from a reduction of the open position and from increased operational flexibility as additional renewables are installed. The upgrades will help achieve an increase in the units' megawatt outputs by implementing a peak firing mode on the large General Electric 7FA combined-cycle combustion turbines at Lenzie, Tracy and Harry Allen.

These upgrades are in addition to the upgrades approved in Docket No. 21-06001 and shown in table GEN-2:

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[19] As defined in NRS §§ 704.7335 and 704.7332.

TABLE GEN-2

PLANT UPGRADES APPROVED IN 21-06001

Plant	Expected Capacity Upgrade at Peak	Upgrade In-service Date
Chuck Lenzie Block 2	40 MW	May 31, 2022
Tracy CC	36 MW	May 31, 2022
Silverhawk – Turbine Upgrades	40 MW	May 31, 2022
Silverhawk – Wet Compression	30 MW	May 31, 2022
Harry Allen CC	45 MW	May 31, 2023

The wet compression projects are planned at the Clark Peakers, Harry Allen 3 and 4, and Sun Peak. The peak firing projects are proposed for Chuck Lenzie CC Blocks 1 and 2, Harry Allen CC, and Tracy CC. Power augmentation is also proposed on the Clark Mountain Units 3 and 4. This power augmentation is already installed on the units, but current permit limitations don't allow operation. The expected costs and performance are listed in Table GEN-3.

TABLE GEN-3

COMBUSTION TURBINE CAPACITY UPGRADES

Plant	Expected Capacity Upgrade at Peak	Expected Project Cost	Upgrade In-Service Date
Requesting Approval			
Chuck Lenzie Blocks 1 and 2	24 MW	$12,000,000	May 31, 2024
Harry Allen CC	12 MW	$6,000,000	May 31, 2024
Tracy CC	12 MW	$6,000,000	May 31, 2024
Not Requesting Approval			
Sun Peak 3,4,5	21 MW	$8,600,000	May 31, 2023
Clark Peakers	60 MW	$18,900,000	May 31, 2022
Harry Allen 3 and 4	14 MW	$7,500,000	May 31, 2022
Clark Mountain 3 and 4	14 MW	0	May 31, 2023

The Clark Mountain units do not have a projected project cost since they have a power augmentation system that was commissioned but requires a permit modification to allow for additional startup/shut-down emissions. The Companies are pursuing permit modifications to allow this peak operation.

NV Energy has the opportunity to install the wet compression systems on the Clark Peakers and the Harry Allen peaking units before the summer of 2022 and believes it is prudent to add this capacity as soon as possible. Since the installation will occur before this filing is adjudicated, the Companies are not requesting approval of the wet compression projects for the Clark Peakers and for Harry Allen Units 3 and 4. They are provided in this narrative for informational purposes only. It was not originally believed that the installation on the Sun Peak unit could be completed prior to this coming summer, however, the Companies now believe that it can install the Sun Peak wet compression upgrades prior to the summer of 2022 and operate under the current heat input limits, based on ambient conditions. The Companies are continuing to pursue permit modifications for heat input to allow full utilization of the units' capability with or without wet compression operation under all ambient conditions. This permitting is not expected to be completed until 2023. Since this change was identified after the analysis was completed for the Preferred Plan, the Sun Peak wet compression project is included in the Preferred Plan. However, the Companies are not asking for approval of this project in this Amendment.

The simple-cycle wet compression projects will allow demineralized water to be injected prior to the unit's compressor, which increases the density of the compressed air and allows a higher turbine output. Since the units will see an increased operational risk due to the addition of the water, the units will be required to have a borescope inspection completed after 300 hours of operation with the wet compression projects. Due to this maintenance requirement, the operation of the units with wet compression will be limited to 300 hours per peak period. Additional variable maintenance costs will be assigned to operation with wet compression to ensure the unit operation is economically utilized while addressing the additional maintenance expenses.

The peak firing upgrades to the General Electric combustion turbines at Chuck Lenzie Blocks 1 and 2, Harry Allen CC and the Tracy CC are expected to increase the peak capacity of each combined-cycle block by approximately 12 MW. This upgrade will utilize the existing equipment but realize the additional capacity through new control upgrades utilizing the existing burners. These projects are estimated to cost $12 million per combined-cycle block ($6 million per combustion turbine) and will provide additional generation capacity at peak until the units' retirements. It should be noted that the peak firing operation does come at additional fired-hour costs under the Long-Term Service Agreement ("LTSA"). The LTSA would assign additional "fired cost" while operating in peak firing mode. Additional variable maintenance costs will be assigned to operation with peak firing to ensure the unit operation is economically utilized while addressing the additional maintenance expenses. This project will provide additional generation capacity and operational flexibility improvements until the units' retirements.

NV Energy is requesting approval of the peak firing projects at Chuck Lenzie Blocks 1 and 2, Harry Allen CC and Tracy CC in this docket.

b. Thermal Storage Project

NV Energy is requesting approval of a thermal energy storage project for the Chuck Lenzie Generating Station. The project would install new thermal storage tanks, piping and pumping systems that will use the existing plant chillers to produce and store chilled water during off peak hours. This thermal energy storage project will allow the chillers to be turned off for up to six hours a day, during which time the turbines will use chilled water made previously. Removing the chillers from service during the hours with the largest open position will reduce the plant auxiliary load by 18 MW in each of these key hours, without diminishing the plant capacity. Since the Chuck Lenzie Generating Station is the only combined-cycle plant that currently has chillers, it is the only plant being considered for this project.

The project has an estimated cost of $13 million and would be in service by the summer of 2024.

c. Silverhawk Peaking Plant

Consistent with the Nevada Administrative Code, the Companies' amended supply plan contains a diverse set of alternative plans.[20] As part of the Alternate Plan a simple cycle gas turbine is presented as diverse alternative to the 2-hour battery energy storage system BESS that is requested as part of the Preferred Plan, The Companies modeled the Silverhawk Peaking Plant individually and as part of the Alternate Plan. The Silverhawk Peaker project would install a simple cycle gas turbine(s) rated at 200 MW, a 500 KV GSU transformer and expansion of the Silverhawk switchyard. The new peaking unit(s) would be rated a nominal 200 MW and would be commercially operational by the summer of 2024. The peaking units have the advantage of providing energy any time it is needed on the system, regardless of ambient conditions.

NV Energy completed a brownfield site screening and determined that Silverhawk was the only existing plant site conducive to installation of new turbine units by the summer of 2024. The Silverhawk plant site is adjacent to the Kern River natural gas line and is not believed to have transmissions constraints that would restrict the use of the plant. NV Energy also owns and controls the plant site and has adequate room on the site for the addition of new units. NV Energy estimates the cost of the project to be $272 million.

The Generation alternatives were based on the project modeling information provided in Confidential Technical Appendix GEN-2.

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[20] *See* NAC 704.937.

SECTION 6. AMENDMENTS TO SUPPLY SIDE PLAN - RENEWABLES

A. Introduction

In this filing, the Companies are seeking the approval of one new 25 MW geothermal PPA, the development of a 220 MW grid-tied BESS, and to study the development of a 1,000 MW pumped storage hydro ("PSH") project. The geothermal project and the PSH project are located in Sierra's territory while the grid-tied BESS is located in Nevada Power's territory. The Companies seek approval of these projects for the following reasons.

First, all three projects would provide reliable peak capacity. Second, the projects allow the Companies to satisfy a growing need to provide new and existing customers with sustainable green energy around the clock. There is a growing movement within the Nevada business community to move towards sourcing electrical generation from zero-carbon, renewable generation. Although Nevada is a long-time leader in promoting renewable generation, many Nevada businesses have their own corporate sustainability objectives that may be more aggressive than the state's objectives. The Companies are working with these customers to assist them in achieving their energy goals and objectives. For example, Nevada Power filed, and the Commission subsequently approved, an energy supply agreement ("ESA") that allows the Allegiant Stadium (a/k/a LV Raiders Stadium) to be powered by 100 percent renewable energy generated by the Southern Bighorn Solar project. More recently, the Commission approved an ESA between Nevada Power and Google allowing its southern Nevada data center to be served by the Dry Lake Solar and Chuckwalla Solar facilities.[21] Additionally, the Companies just completed the first open season under the updated NV GreenEnergy Rider ("NGR") tariffs approved by the Commission on December 7, 2021.[22] Such open seasons will be conducted annually to meet participating customers' interest in renewable energy. The new proposed geothermal project is not dependent on the weather and can, therefore, produce around the clock and does not need a co-located energy storage to deliver energy in the evenings. Third, these projects allow the Companies to continue to take advantage of favorable pricing for both geothermal and energy storage. Fourth, the projects mitigate a growing need to manage excess solar photovoltaic generation by delivering green energy at night in the case of the geothermal project; or help capture daytime solar generation for delivery later in the evening in the case of the battery.

Finally, it is the right action to take. The Companies' commitment to renewables goes beyond just meeting standards; it is about leading the way. The Companies have fostered renewable development since before the establishment of an RPS, having signed their first geothermal contract in 1986. The Companies' customers currently benefit from one of the most diverse

[21] LV Raiders Stadium ESA was approved in Docket No. 19-10012; Southern Bighorn Solar project was approved in Docket No. 19-06039; Google ESA was approved in Docket No. 19-12017; and Dry Lake Solar and Chuckwalla Solar were approved in Docket No. 20-07023.

[22] Docket Nos. 21-09018 and 21-09019.

renewable energy portfolios in the nation, including 56 geothermal, solar, solar plus storage, wind, biomass, hydro, and waste heat renewable energy projects. The Companies received Commission approval for 3,269 MW of solar and 1,508 MW of battery storage since December 2018 alone. All these efforts align with the Companies' ongoing commitment to support economic development throughout Nevada by working with many partners to attract, retain, and expand industry to diversify the economy. Even when a portion of the renewable energy is allocated to specific jobs-generating customers, it also promotes overall economic development, creates additional tax base for the state and counties, and lowers the total amount of energy that otherwise would have to come from carbon-based generating resources. This benefits the environment and the citizens of the state as a whole and aligns with the state's overall policy goals.

B. Overview

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

In their most recent RPS Annual Compliance filing, Docket No. 21-04019, Nevada Power and Sierra both exceeded their respective 2020 RPS credit requirements of 22 percent. Nevada Power ended 2020 at 28.5 percent, a record for Nevada Power, while Sierra ended 2020 with 30.2 percent. Although the Company is still in the process of finalizing the 2021 RPS Compliance filing, it expects that Nevada Power and Sierra will come in slightly higher with two new renewable facilities declaring commercial operation during 2021 and a third facility delivering test energy as it completes the commissioning process.

As of January 31, 2022, Nevada Power had approximately 1,552.5 MW of renewable generating resources operating and delivering renewable energy to meet the energy needs of its customers.[23] In addition, Nevada Power also ended January 2022 with nine solar PV projects in various stages of development and construction, totaling an additional 2,044 MW of new generation[24]. Eight of nine projects include co-located BESS, which offers flexibility by allowing Nevada Power to store generation when demand and prices are low and release it back to the grid when demand and prices start to rise. This helps optimize must-take renewable resources, like solar PV and wind, where generation and load do not always align.

Table REN-1, below, lists Nevada Power pipeline projects, showing the facility name, resource type, approval docket number, projected commercial operation date, nameplate capacity (AC), storage capacity, and energy and capacity allocation, as approved by the Commission in the approval order.

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[23] The 1,552.5 MW total divides the Nevada Solar One 69 MW agreement between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission. It also includes the two PC only agreements: Nellis 1(13.2 MW) and Las Vegas Water District (3 MW) and Nevada Power's allocation of Hoover (237.6 MW).

[24] The 2,044 divides the capacity of Hot Pot (NPC 196 MW, SPPC 154 MW), Iron Point (NPC 140 MW, SPPC 110 MW), Moapa (NPC 60 MW, SPPC 140 MW) and Southern Bighorn (NPC 180 MW, SPPC 120 MW) based on the Commission's order approving the projects.

TABLE REN-1
NEVADA POWER PIPELINE RENEWABLE GENERATION AS OF JANUARY 31, 2022

Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	Energy / Capacity Allocation NPC	SPPC
Eagle Shadow Mountain	Solar PV	18-06003	01/01/22	300		300	
Moapa (Arrowhead Canyon) Solar [a.]	Solar PV	19-06039	12/01/22	200	75	60	140
Southern Bighorn Solar Farm [a.]	Solar PV	19-06039	09/01/23	300	135	180	120
Chuckwalla	Solar PV	20-07023	12/01/23	200	180	200	
Boulder Solar III	Solar PV	20-07023	12/31/23	128	58	128	
Dry Lake Solar	Solar PV	20-07023	12/31/23	150	100	150	
Hot Pot [b.]	Solar PV	21-06001	12/31/24	350	350	196	154
Iron Point [b.]	Solar PV	21-06001	12/31/23	250	200	140	110
Gemini Solar [c.]	Solar PV	19-06039	05/01/24	690	380	690	
				2,568	1,478	2,044	524

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)

As of January 31, 2022, Sierra had approximately 692.4 MW of renewable generating resources operating and delivering renewable energy to meet the energy needs of its customers.[25] In addition, Sierra ended January 2022 with six solar PV projects in various stages of development and construction, totaling an additional 824 MW of new generation. All six projects include co-located BESS. Like Nevada Power, battery storage offers flexibility by allowing Sierra to store generation when demand and prices are low and release it back to the grid when demand and prices start to rise. This helps optimize must-take renewable resources, like solar PV, where generation and load do not always align.

Table REN-2, below, lists Sierra's future projects, showing the facility name, resource type, approval docket number, projected commercial operation date, nameplate capacity (AC), storage capacity, and energy and capacity allocation, as approved by the Commission in the approval order.

[25] The 692.4 MW total divides the Nevada Solar One 69 MW agreement between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission. It excludes Hooper Hydro (.8 MW), where Sierra does not claim the PCs from the generation.

TABLE REN-2
SIERRA PIPELINE GENERATION AS OF JANUARY 31, 2022

Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	Energy / Capacity Allocation SPPC	NPC
Dodge Flat	Solar PV	18-06003	Q2 2022	200	50	200	
Fish Springs	Solar PV	18-06003	Q2 2022	100	25	100	
Moapa (Arrowhead Canyon) Solar [a.]	Solar PV	19-06039	12/01/22	200	75	140	60
Hot Pot [b.]	Solar PV	21-06001	12/31/24	350	350	154	196
Southern Bighorn Solar Farm [a.]	Solar PV	19-06039	09/01/23	300	135	120	180
Iron Point [b.]	Solar PV	21-06001	12/31/23	250	200	110	140
				1,400	835	824	576

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)

The following is a summary of Nevada Power's and Sierra's portfolios of renewable facilities that are or will contribute to Nevada Power and Sierra meeting the RPS requirements as of January 2022. The list below does not include the Mojave community based solar project, short-term agreements or projects that are dedicated to supporting commitments to meet customer-specific requirements for renewable energy under the NV GreenEnergy Rider ("NGR") program.[26] The Companies will be making a separate compliance filing required by Schedule No. NGR in April 2022.

Nevada Power

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

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

[26] Nevada Power entered into a short-term purchase agreement with Tonopah Solar Energy for the output of the Crescent Dunes Solar Thermal Plant for the period December 21, 2021, through September 30, 2024, which is not expected to impact RPS compliance outlook. The 0.350-MW Mojave project reached commercial operation in December of 2021 and its contribution to the RPS compliance outlook is negligible.

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

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

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

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

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

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

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

10. Boulder Solar 1

Boulder Solar 1 is a 100 MW solar PV project located in Boulder City, Nevada. The project was approved by the Commission in 2015. The solar project completed commissioning and declared commercial operation in December 2016. The 30-year PPA terminates on December 31, 2036.

11. Las Vegas Valley Water District ("LVVWD")

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

12. Mountain View Solar

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

13. Nellis Air Force Base, Solar Star

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

14. Nellis Solar Array II

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

15. Nevada Solar One

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

16. Silver State Solar

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

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

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

19. Eagle Shadow Mountain Solar Farm
Eagle Shadow Mountain Solar Farm is a 300 MW solar PV facility located on the Moapa River Indian Reservation in Clark County, Nevada. The solar array is online, capable of generating approximately 265 MW and is projected to declare commercial operations in Q1 2023. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

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

21. Arrow Canyon Solar
Arrow Canyon Solar, formerly Moapa Solar, is a 200 MW solar PV facility with 75 MW of BESS capacity that will be located on the Moapa Band of Paiutes Indian Reservation north of Las Vegas, Nevada. The solar array is projected to declare commercial operations in December 2022. The energy, capacity and PCs generated by the facility will be split 70 percent to Sierra, 30 percent to Nevada Power. The 25-year PPA was approved by the Commission in Docket No. 19-06039.

22. Southern Bighorn Solar
Southern Bighorn Solar is a 300 MW solar PV facility with 135 MW of BESS capacity that will be located on the Moapa River Indian Reservation, north of Las Vegas, Nevada. The solar array is projected to declare commercial operations in December 2023. The energy, capacity and PCs generated by the facility will be split 40 percent to Sierra, 60 percent to Nevada Power. The 25-year PPA was approved by the Commission in Docket No. 19-06039.

23. Gemini Solar
Gemini Solar is a 690 MW solar PV facility with 380 MW of BESS capacity that will be located in Clark County, approximately 25 miles northeast of Las Vegas, Nevada. The solar

array is projected to declare commercial operations in December 2023. While 100 percent of the energy and capacity generated by the facility will go to Nevada Power, only 60 percent of the associated PCs will be assigned to Nevada Power, with the balance assigned to Sierra. The 25-year PPA was approved by the Commission in Docket No. 19-06039.

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

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

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

27. Hot Pot Solar
Hot Pot Solar is a 350 MW solar PV facility located near Valmy in Humboldt County, Nevada. The facility will be company-owned. It was approved by the Commission in Docket No. 21-06001. The energy and PCs from the projects will be split between Nevada Power and Sierra, 56 percent Nevada Power, 44 percent Sierra, based on the Commission's order approving the project. The project is expected to declare commercial operations in December 2024.

28. Iron Point Solar
Iron Point Solar is a 250 MW solar PV facility located near Valmy in Humboldt County, Nevada. The facility will be company-owned. It was approved by the Commission in Docket No. 21-06001. The energy and PCs from the projects will be split between Nevada Power and Sierra, 56 percent Nevada Power, 44 percent Sierra, based on the Commission's order approving the project. The project is expected to declare commercial operations in December 2023.

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

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

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

32. <u>Goodsprings Recovered Energy Generation Station</u>
The Goodsprings Recovered Energy Generation Station is located 35 miles south of Las Vegas, Nevada. It is a 7.5 MW generating plant that converts waste heat from a natural gas pipeline compressor station to electric energy. The project was approved by the Commission in 2008 and it started producing energy in 2010. The project is owned by Nevada Power.

33. <u>Dry Lake Solar</u>
The Dry Lake Solar project is 150 MW solar PV facility with 100 MW of BESS capacity located 20 miles northeast of Las Vegas adjacent to the Harry Allen combined cycle station and is owned by Nevada Power. The project is projected to declare commercial operations in December 2023. The 25-year pricing was approved by the Commission in Docket No. 20-07023.[27]

34. <u>Chuckwalla Solar</u>
The Chuckwalla Solar project is a 200 MW solar PV facility with 75 MW of BESS capacity that will be located on the Moapa River Indian Reservation, north of Las Vegas, Nevada. The project is projected to declare commercial operations in December 2023. The 22-year PPA was approved by the Commission in Docket No. 20-07023.

35. <u>Boulder Solar III</u>
The Boulder Solar III project is a 128 MW solar PV facility with 58 MW of BESS capacity located in Boulder City, Nevada. The project is projected to declare commercial operations in December 2023. The 12-year PPA was approved by the Commission in Docket No. 20-07023.

[27] The project is company-owned. The Commission approved PPA-style pricing per the method set forth in NRS § 704.752.

Sierra

1. Beowawe Geothermal Power Plant
   The Beowawe facility is a 17.7 MW geothermal facility located in Eureka County and is owned by Terra-Gen Power. The plant was placed into service in 1985 and was originally under contract with Southern California Edison. However, in 2006, Sierra entered into a 20-year contract for renewable energy that expires on April 21, 2025.

2. Brady Geothermal Power Plant
   The Brady facility is a 24 MW geothermal facility located in Churchill County northeast of Fernley, Nevada. The plant started producing energy in 1992. Sierra has a 30-year PPA with the facility that expires on July 29, 2022.

3. Burdette Geothermal Power Plant
   The Burdette facility is a 26 MW geothermal project located in Washoe County near Steamboat, Nevada. The plant went into service in 2006. Sierra has a 20-year PPA with the facility that expires on December 31, 2026.

4. Galena 3 Geothermal Power Plant
   The Galena 3 facility is a 26.5 MW geothermal project located in Washoe County south of Reno near Steamboat, Nevada. The plant went into service in 2008. Sierra has a 20-year PPA with the facility that expires on December 31, 2028.

5. Steamboat 2 Geothermal Power Plant
   The Steamboat 2 facility is a 13.4 MW geothermal project located in Washoe County, Nevada. The plant began producing energy in 1992. Sierra has a 30-year PPA with the facility that expires on December 12, 2022.

6. Steamboat 3 Geothermal Power Plant
   The Steamboat 3 facility is a 13.4 MW geothermal project located in Washoe County, Nevada. The plant began producing energy in 1992. Sierra has a 30-year PPA with the facility that expires on December 18, 2022.

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

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

9. Dodge Flat Solar
   Dodge Flat Solar is a 200 MW solar PV facility located in Washoe County, Nevada. The project incorporates 50 MW of BESS. The solar array is projected to declare commercial operations in the first quarter of 2022. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

10. Fish Springs Ranch Solar
    Fish Springs Ranch is a 100 MW solar PV facility located in Washoe County, Nevada. The project incorporates 25 MW of BESS. The solar farm is projected to declare commercial operation in the first quarter of 2022. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

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

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

13 Hot Pot Solar
   Hot Pot Solar is a 350 MW solar PV facility located near Valmy in Humboldt County, Nevada. The facility will be company-owned. It was approved by the Commission in Docket No. 21-06001. The energy and PCs from the projects will be split between Nevada Power and Sierra, 56 percent Nevada Power, 44 percent Sierra, based on the Commission's order approving the project. The project is expected to declare COD in December 2024.

14 Iron Point Solar
   Iron Point Solar is a 250 MW solar PV facility located near Valmy in Humboldt County, Nevada. The facility will be company-owned. It was approved by the Commission in Docket No. 21-06001. The energy and PCs from the projects will be split between Nevada Power and Sierra, 56 percent Nevada Power, 44 percent Sierra, based on the Commission's order approving the project. The project is expected to declare COD in December 2023.

15 <u>Fleish Hydro Power Plant</u>

The Fleish facility is a 2.4 MW hydro-electric project located on the California/Nevada border southwest of Reno, Nevada. The hydro facility is owned by Truckee Meadows Water Authority ("TMWA") and went into commercial operation in 2008. Sierra has a 20-year PPA with the facility that expires on June 1, 2028.

16 <u>New Lahontan Truckee Carson Irrigation District Hydro Power Plant</u>

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

17 <u>Verdi Hydro Power Plant</u>

The Verdi facility is a 2.4 MW hydro-electric project located in Washoe County, Nevada. The hydro facility is owned by TMWA and went into service in 2009. Sierra has a 20-year PPA with the facility that expires on June 1, 2029.

18 <u>Washoe Hydro Power Plant</u>

The Washoe facility is a 2.5 MW hydro-electric project located in Washoe County, Nevada. The hydro facility is owned by TMWA and went into service in 2008. Sierra has a 20-year PPA with the facility that expires on June 1, 2028.

19 <u>Truckee Meadows Waste Water Facility ("TMWWF")</u>

The TMWWF is 0.8 MW biogas facility with which Sierra has a PC only purchase agreement. The agreement was approved by the Commission in 2006. The 20-year contract expires on December 12, 2024.

20 <u>Kingston Hydro</u>

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

21 <u>Mill Creek Hydro</u>

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

22 RO Ranch Hydro

RO Ranch Hydro is a small, 0.225 MW, hydro facility located in Churchill County, Nevada. It is owned by BTAZ Nevada, LLC. The facility received a rebate under Sierra's Hydro Demonstration Program. Under the demonstration program the rights to the PCs are assigned to Sierra. The PCs from this facility are included in the "RENGEN" non-solar credit total designation reported in the RPS Annual Compliance filing.

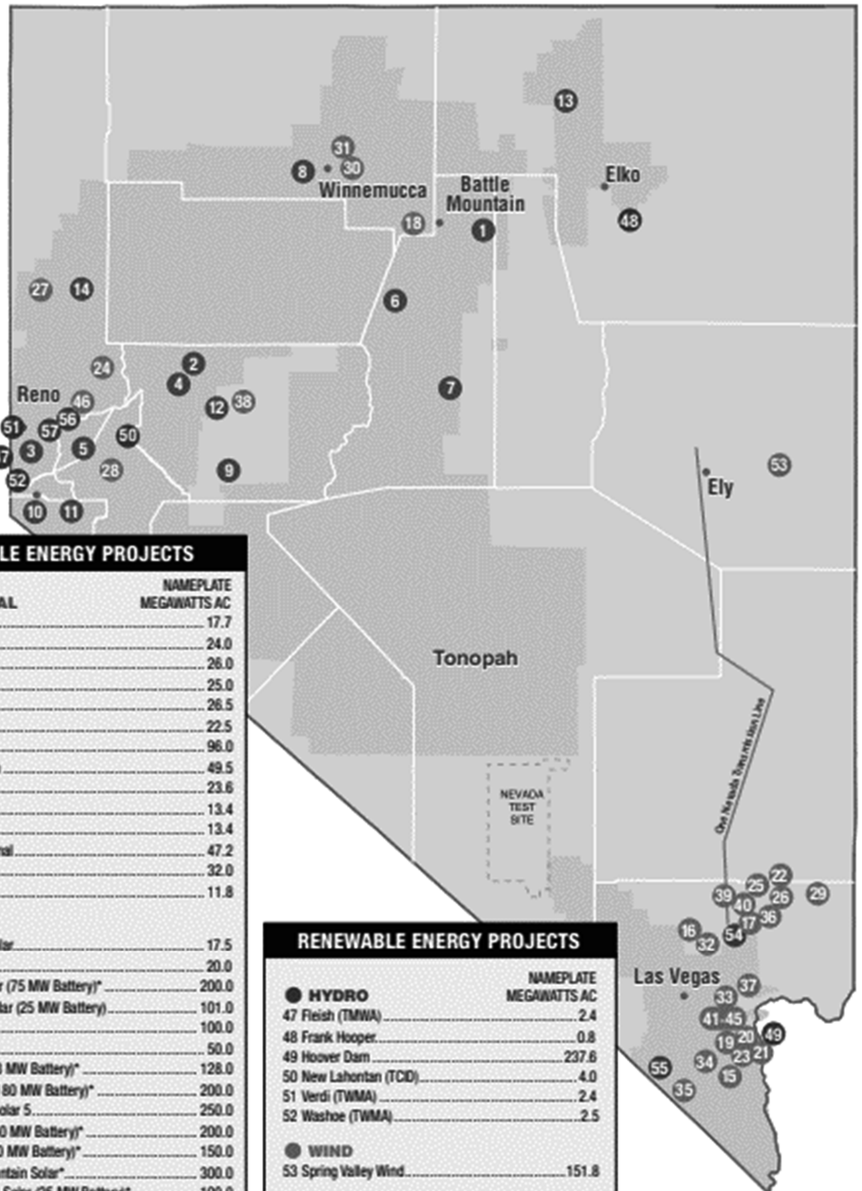
23 Rye Patch Hydro

Rye Patch Hydro is a small, 0.75 MW, hydro facility located in Pershing County, Nevada. It is owned by the Pershing County Water Conservation District of Nevada. The facility received a rebate under Sierra's Hydro Demonstration Program. Under the demonstration program the rights to the PCs assigned to Sierra. The energy credits from this facility are included in the "RENGEN" non-solar credit total designation reported in the Annual Compliance filing.

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

FIGURE REN-1 NVE RENEWABLE ENERGY MAP

NV Energy's Clean Energy Commitment



RENEWABLE ENERGY PROJECTS

GEOTHERMAL	NAMEPLATE MEGAWATTS AC
1 Beowawe Power	17.7
2 Brady	24.0
3 Burdette	26.0
4 Desert Peak 2	25.0
5 Galena 3	26.5
6 Jersey Valley	22.5
7 McGinness Hills	96.0
8 NGP Blue Mountain	49.5
9 Salt Wells	23.6
10 Steamboat 2	13.4
11 Steamboat 3	13.4
12 Stillwater Geothermal	47.2
13 Tuscarora	32.0
14 USG San Emidio	11.8
SOLAR	
15 ACE Searchlight Solar	17.5
16 Apex Nevada Solar	20.0
17 Arrow Canyon Solar (75 MW Battery)*	200.0
18 Battle Mountain Solar (25 MW Battery)	101.0
19 Boulder Solar I	100.0
20 Boulder Solar II	50.0
21 Boulder Solar III (58 MW Battery)*	128.0
22 Chuckwalla Solar (180 MW Battery)*	200.0
23 Copper Mountain Solar 5	250.0
24 Dodge Flat Solar (50 MW Battery)*	200.0
25 Dry Lake Solar (100 MW Battery)*	150.0
26 Eagle Shadow Mountain Solar*	300.0
27 Fish Springs Ranch Solar (25 MW Battery)*	100.0
28 Fort Churchill Solar Array	19.5
29 Gemini Solar (380 MW Battery)*	690.0
30 Hot Pot Solar Project (280 MW Battery)*	350.0
31 Iron Point Solar Project (200 MW Battery)*	250.0
32 Mountain View Solar	20.0
33 Nellis Solar Array 2	15.0
34 Nevada Solar One	69.0
35 Silver State Solar North	52.0
36 Southern Bighorn Solar (135 MW Battery)*	300.0
37 Spectrum Nevada Solar	30.0
38 Stillwater Solar PV	22.0
39 Switch Station 1	100.0
40 Switch Station 2	79.0
41 Techren Solar I	100.0
42 Techren Solar II	200.0
43 Techren Solar III	25.0
44 Techren Solar IV	25.0
45 Techren Solar V	50.0
46 Turquoise Solar	50.0

* In development or under construction.

RENEWABLE ENERGY PROJECTS

HYDRO	NAMEPLATE MEGAWATTS AC
47 Fleish (TMWA)	2.4
48 Frank Hooper	0.8
49 Hoover Dam	237.6
50 New Lahontan (TCID)	4.0
51 Verdi (TWMA)	2.4
52 Washoe (TWMA)	2.5
WIND	
53 Spring Valley Wind	151.8
BIOMASS / METHANE / OTHER	
54 Apex Landfill Renewable Energy	12.0
55 Goodsprings Energy Recovery Station	5.0
56 Lockwood Renewable Energy Facility	3.2
57 Truckee Meadows Water Reclamation Facility	0.8
RENEWABLEGENERATIONS PROJECTS (Statewide)	
Total Incentivized Private Rooftop Solar, etc.	316.4
Total NV Energy Clean Energy Resources (MW)	**5,114.1**

ENERGY EFFICIENCY

2020 Peak Demand Reduction Capacity Statewide	210.1 MW
Cumulative Energy Savings Statewide	3,838,565 MWh

Calculated for Years 2005 through 2020

NVEnergy

Updated 01-19-2022

C. Compliance Outlook

Nevada Power and Sierra both exceeded the 2020 RPS requirement of 22 percent. They are also expected to exceed the 2021 RPS requirement of 24 percent when the company reports 2021 results in April 2022. Nevada's RPS is a credit requirement calculated based on total retail megawatt hour sales. Under changes to the RPS passed and signed into law during the 2019 Legislative Session, the RPS increases to 29 percent in 2022, 34 percent in 2024, 42 percent in 2027, and 50 percent in 2030 and beyond. The RPS also no longer contains a solar carve out. The revised RPS rules now permit utilities to exclude from the RPS calculation retail sales that are covered under a green energy tariff pursuant to NRS 704.738. The new rules also permit the use of PCs from large hydro facilities, such as Hoover Dam.

While the new law doubled the RPS from 25 to 50 percent, and compressed the timeline to achieve the 50 percent standard, it retains several rules allowing the Companies to meet their annual credit requirements with the use of credit multipliers, station usage credits, and demand side management ("DSM") credits. The use of these non-net energy PCs will, however, eventually expire. In particular, station usage[28] and multiplier credits are restricted to generating units placed in service on or before December 31, 2015, and the use of DSM credits is being phased out and will end starting in 2025.

Nevada Power

Nevada Power's compliance outlook can be summed up as positive. While the company has been very successful in building a pipeline of new projects to meet its future credit needs, Nevada Power's compliance outlook is not without risk. Until the nine pipeline projects in Table REN-1 achieve commercial operation, there is the risk of delays or cancelations. Second, there is the risk that one or more of its operating projects could experience an unexpected issue, resource and/or mechanical, and fall short on its generating commitments. Finally, the company could experience higher than expected load growth. With higher RPS percentages on the horizon, even a small increase in retail load growth can increase the company's credit need by thousands of credits.

In summary, while Nevada Power is currently positioned to meet its future credit commitments (RPS, NGR, and 704B obligations), experience has shown that renewable projects, both operating and pipeline, can be unpredictable. Nevada Power will continue to explore all options to procure the renewable generating resources needed to further progress towards becoming net-zero carbon-free by 2050. To this end, the Companies consider the RPS a floor, not a ceiling.

[28] There is an exception under NRS § 704.758215(3)(b) for geothermal plants and the station usage associated with the extraction and transportation of geothermal brine.

Sierra

Sierra's compliance outlook can be summed up as near-term cautiously optimistic and long-term bright. While Sierra has been very successful in building a pipeline of new projects to meet its future credit needs, its compliance outlook is not without risk. Until the six pipeline projects in Table REN-2 achieve commercial operation, there is the risk of delays or cancelations. Calendar year 2022 is especially critical with four of the seven pipeline projects scheduled to declare commercial operation. Sierra will also lose the energy and PCs from three long-term geothermal projects, Brady, Steamboat 2 and Steamboat 3. The company was unable to reach an agreement with the counterparty on extending or renewing the PPAs, and all three agreements will expire in 2022. Unlike Nevada Power, Sierra does not have a level of cushion in the event that one or more of its pipeline projects is delayed. There is the risk that one or more if its operating projects could experience an unexpected outage, resource and/or mechanical, and fall short on its generating commitments or Sierra could experience higher than expected load growth. Like Nevada Power, with the higher RPS percentages on the near horizon, even a small increase in retail load growth can increase the company's credit need by thousands of credits. Finally, environmental events, such as forest fires, that could impact solar generation and renewable energy delivery are more likely for Sierra as compared to Nevada Power.

In summary, while Sierra is currently positioned to meet its future credit commitments (RPS, NGR, 704B and service agreement obligations), experience has shown that renewable projects, both operating and pipeline, can be unpredictable. Sierra will continue to explore all options, including issuing renewable energy RFPs, to procure the renewable generating resources that are needed to continue its commitment to becoming carbon-free. As with Nevada Power, the RPS is a floor, not a ceiling.

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 of the changes from Senate Bill 358 ("SB358") and codified in NRS §§ 704.7801 through 704.7828. In determining future PC needs, the Companies must carefully consider two 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; and

- 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.

For this filing, the Companies used the same renewable placeholder buildout developed for the 2021 Joint IRP Preferred Plan. 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 PPAs expire in accordance with the contract terms and are not automatically renewed;[29]

- The Companies adjusted the expected amount of energy and PCs from renewable facilities for the period of 2021-2024 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 systems placed into service before December 31, 2015, qualify for the solar multiplier; systems placed into service after do not qualify;

- The plan assumes that the percent of annual PC requirements met from demand side management ("DSM") measures are limited to no more than 10 percent of the credit total for 2021 through 2024 before dropping to zero effective 2025. The plan also assumes, based on current DSM kPC projections, that Sierra may not have a sufficient number of DSM PCs to completely fill the 10 percent cap in 2023 and 2024;

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

- Nevada Power repaid the final 538,438 kPCs that it owed Sierra in 2021. The balance owed to Sierra is now zero;

[29] 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 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 would continue to qualify for station usage credits, while all other technologies would no longer qualify;

- The plan accounts for all Commission approved and existing NV GreenEnergy Rider ("NGR") and Energy Supply Agreements ("ESAs") as of January 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 incorporates the results of the 2022 NGR Open Season;

- 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;

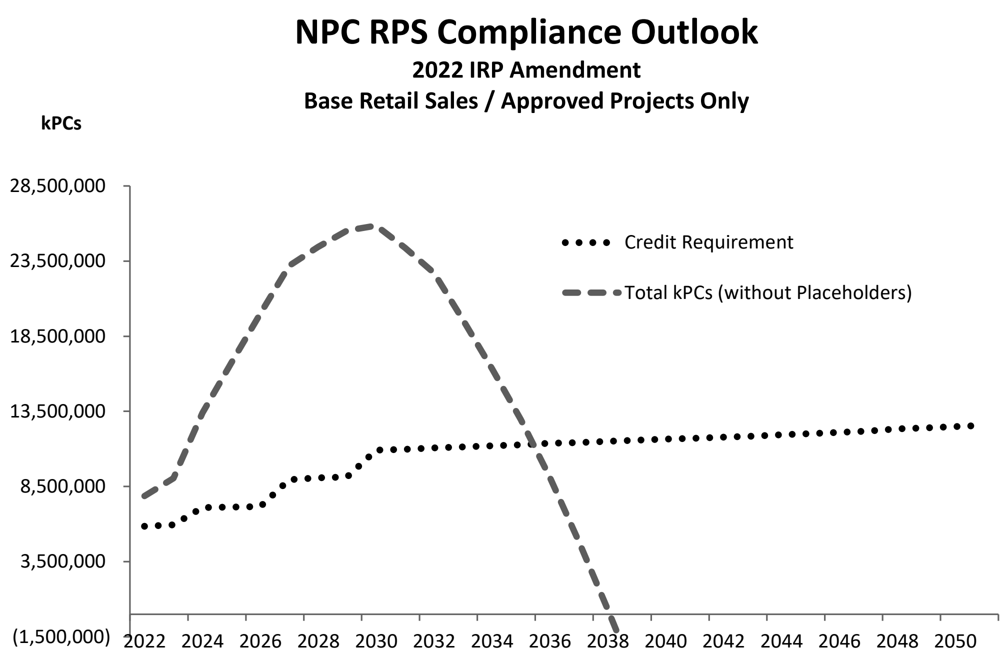
- The plan assumes the approval of the proposed the North Valley geothermal ("North Valley Geothermal" or "North Valley") PPA. North Valley Geothermal is a 25 MW geothermal plant with an estimated commercial operation date of December 31, 2022. Sierra will be the sole offtaker of the energy and PCs. 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 will be times when the transmission system cannot accommodate all of the energy being produced making generation curtailment necessary to maintain grid integrity.

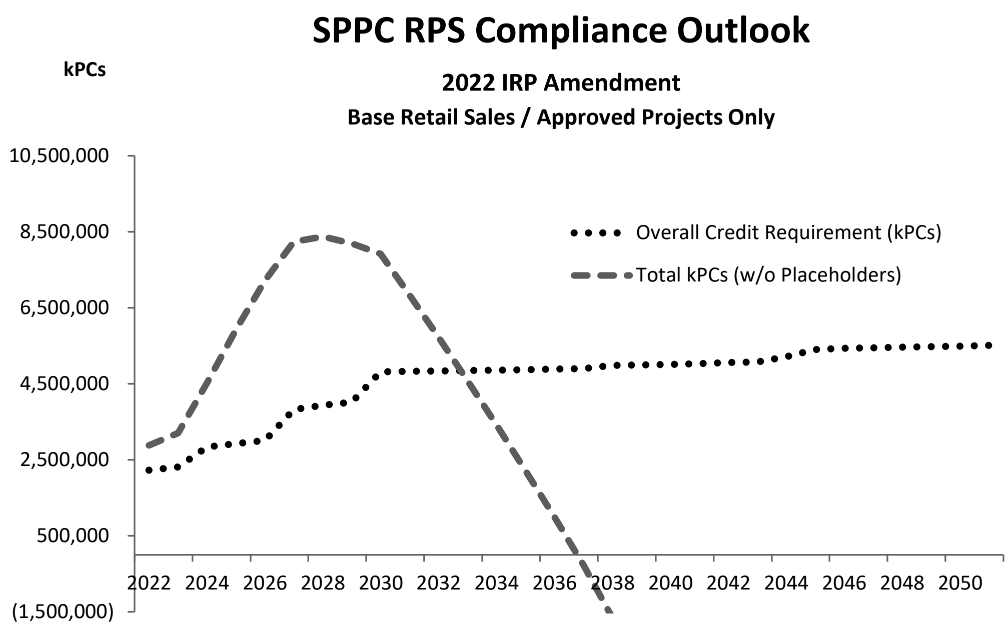
The following Figures REN-2 and REN-3 illustrate the RPS compliance projections for Nevada Power and Sierra. This first set of charts assumes that no action is taken to add new renewable resources. Both figures are based on each company's current renewable portfolio and above planning protocol under a base load projection.

FIGURE REN-2
NEVADA POWER RPS OUTLOOK APPROVED PROJECTS ONLY
(NO EXTENSIONS, PLACEHOLDERS, OR PURCHASES)



Based on the above Nevada Power is projected to be RPS non-compliant in 2036.

FIGURE REN-3
SIERRA RPS OUTLOOK APPROVED PROJECTS ONLY
(NO EXTENSIONS, PLACEHOLDERS, OR PURCHASES)



Based on the above, Sierra is projected to be RPS non-compliant in 2033.

Figures REN-4 and REN-5, below, show Nevada Power's and Sierra's RPS compliance outlooks. Sierra's outlook assumes the approval of the North Valley Geothermal with 100 percent of the energy and PCs assigned to Sierra. The outlooks assume the PCs generated by North Valley contribute to Sierra's RPS needs as there is not enough certainty on potential ESAs to allocate otherwise. However, as noted above, any ESAs approved by the Commission that are tied to these projects will receive a portion of the PCs from these projects. As previously stated, all plans assume that all excess PCs are banked, not sold, and all plans assume unlimited banking. The plans also assume that the Companies will replace expiring renewable PPAs throughout the planning horizon in order to maintain renewable capacity. The associated number of PCs are shown on the charts below on a secondary axis. As renewable generation reaches and exceeds 50 percent of retail sales, the associated number of PCs will begin to grow exponentially due to credit banking.

FIGURE REN-4
NEVADA POWER'S RPS OUTLOOK
PREFERRED PLAN WITH PLACEHOLDERS

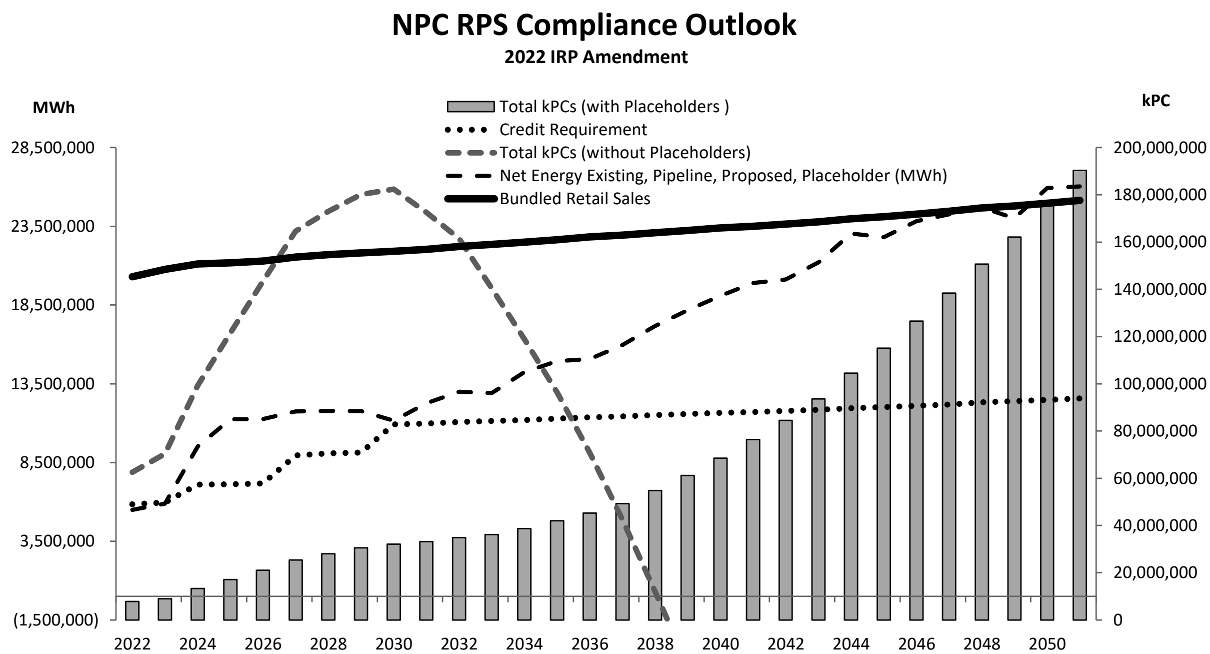


FIGURE REN-5
SIERRA'S RPS OUTLOOK PREFERRED PLAN
WITH NORTH VALLEY GEOTHERMAL & PLACEHOLDERS

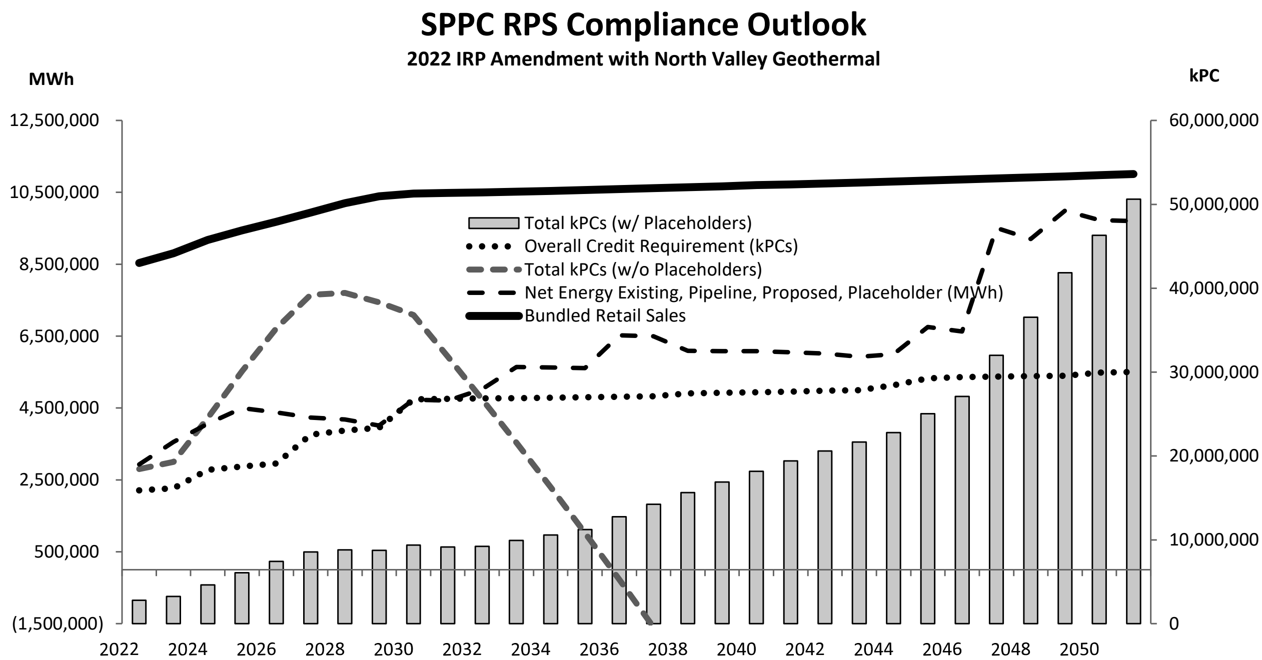
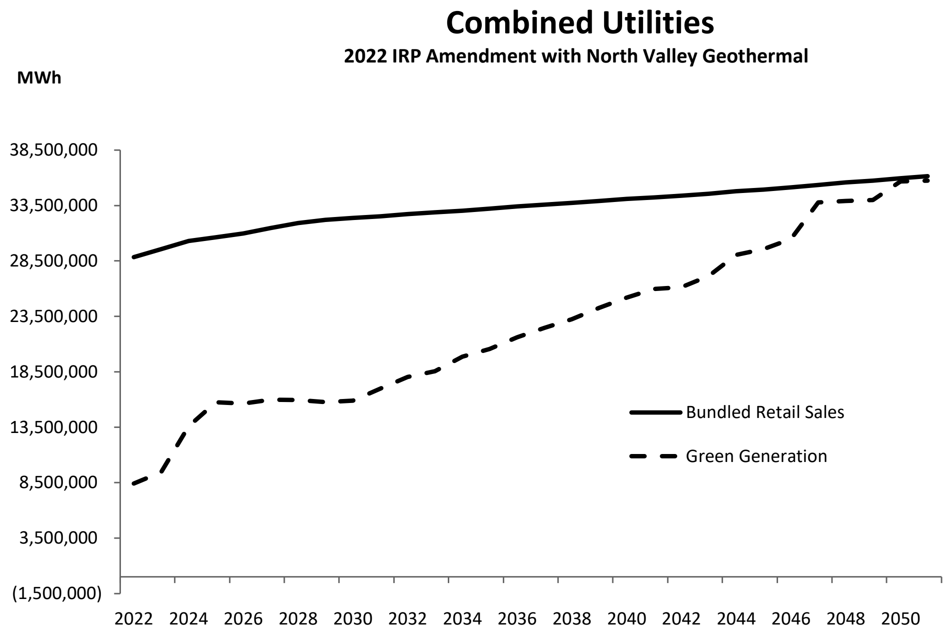


Figure REN-6, below, shows bundled retail sales and total green generation for the combined utilities for illustration purposes only. It does not show total credits, as the key metric to measuring zero-carbon success is total green energy generated during the period rather than total credits accumulated.

FIGURE REN-6
NV ENERGY'S RPS OUTLOOK
WITH NORTH VALLEY GEOTHERMAL & PLACEHOLDERS



In addition to the Preferred Plan shown above, the Companies also modeled an Alternat Plan.

Nevada Power and Sierra will continue to closely monitor their RPS compliance outlooks, recognizing that there are many factors, some outside of the Companies' control, which will ultimately determine whether the Companies will have a sufficient number of PCs to satisfy their respective RPS credit obligations. The objective is to never be put into a reactive position where the Companies must acquire a large number of PCs in a short-time frame in order to maintain compliance. Time expands options, which in turn increases the ability of the Companies to negotiate favorable contracts to acquire renewable generating resources to meet the needs of their customers and to meet or exceed all regulatory and internal requirements. The Companies will also continue to add new renewable resources beyond what is required by the RPS to achieve the state's 2050 clean energy goal.

Technical Appendix REN-1 contains the 12x24 supply table and degradation for North Valley Geothermal. Technical Appendix REN-2 is a list of the placeholders modeled in the Nevada Power Net-Zero Case and Sierra Net-Zero plus North Valley Geothermal Case. It also contains a breakdown of total PCs by year and source for each case.

D. Origination/Renewable Energy

This Amendment proposes two notable resource additions. The Companies are presenting one new utility-scale geothermal power purchase agreement and a Company-owned 220 MW grid-tied BESS. The Companies are also seeking to continue the study and development of a 1,000 MW PSH energy storage facility.

The North Valley Geothermal, if approved, would be the first new geothermal or non-solar facility contracted and presented for approval by the Companies since 2011.[30] The Companies are proposing that the North Valley PPA be 100 percent dedicated to Sierra. North Valley will grow the Companies' portfolio of renewable energy resources to help meet several business and policy objectives including: 1) addition of a cost competitive geothermal resource to the Companies' renewable energy portfolio, 2) providing support to reduce the open capacity, 3) bringing forward a diverse geothermal resource in northern Nevada that is dispatchable and can provide a load-following capability in support of a balanced renewable energy portfolio especially in light of the solar PV and BESS projects that either recently became commercial or are under development support, 4) supporting predictable, weather-independent, and around the clock generating, 5) meeting customers' demand for green energy,[31] 6) continued compliance with the Nevada RPS, and 7) providing economic benefit to the Nevada economy during both construction and operational phases of the project.

Next, the 220 MW, 2-hour duration, BESS located at Reid Gardner represents an innovative means to provide peak capacity and repurposes the site of a retired coal-fired power plant. Its configuration is targeted to address Nevada Power's summer need during the period when solar generation is declining faster than load. The Reid Gardner grid-tied BESS project will be a 100 percent Nevada Power resource and classified as a transmission asset.

Finally, the request to study and contribute to rPlus' continued development of the White Pine project, with its planned eight-hour storage duration and 2031 availability, represents the Companies' efforts to diversify its resource mix with long-duration storage capacity.

The proposed resources are summarized below in Table REN-3.

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[30] The last new geothermal resource was the USG San Emidio facility that reached commercial operation in May 2012. The last new non-solar resource was the Spring Valley Wind facility that reached commercial operation in August 2012. Spring Valley Wind was presented for the Commission's approval in 2010.

[31] Results of 2020 ballot question number 6, available at https://silverstateelection.nv.gov/ballot-questions/.

TABLE REN-3
PROPOSED RESOURCES

Project Name	Counterparty	Agreement Type	Technology	Capacity	Expected Commercial Operation
North Valley	ORNI 36, LLC	PPA 25 years	Geothermal	25 MW (Net)	December 2022
Reid Gardner BESS	Tesla, Inc.	Asset Purchase	Lithium Iron Phosphate ("LFP")	220 MW	May 31, 2023

The Companies have reached a point where they can be selective in choosing projects that not only meet future energy needs, but support other strategic objectives. All of the Companies' renewable projects, both PPA and company-owned, are located in Nevada,[32] delivering renewable energy and economic benefits to the state. In this filing, the Companies are requesting Commission approval of a portfolio of projects that reduces the Companies' reliance on market capacity while increasing energy supply diversity and supporting increased integration of renewable resources.

The North Valley PPA and the Reid Gardner BESS are included in the Companies' Preferred Plan. Approval of these projects will be an important step for the Companies to diversify the renewable energy portfolio, support evening and night-time renewable energy needs, maintain continued compliance with an increasing RPS and meet the state's 2050 clean energy goal while supporting other customer needs. The addition of the North Valley Geothermal, which brings 25 MW of geothermal capacity, is consistent with the Companies' strategy of delivering energy and services that customers value at reasonable rates. The addition of this resource furthers the transformation of the Companies' energy supply portfolio, reducing both carbon emissions and fuel price risk. Finally, as noted above, in the introduction, and below, the updated Preferred Plan positions the Companies to meet the energy needs of their customers.

a. North Valley Geothermal Project

The proposed North Valley project is to be developed by ORNI 36, LLC and located on private land in Washoe County, Nevada. ORNI 36, LLC is wholly-owned by Ormat Nevada Inc. whose parent company is Ormat Technologies Inc. ("Ormat"), a market leading, vertically-integrated, geothermal energy and service provider with over five decades of expertise in the geothermal energy sector. Ormat owns, operates, designs, manufactures and sells geothermal power plants primarily based on the Ormat Energy Converter – a power generation unit that converts low-, medium- and high-temperature heat into electricity. Ormat has engineered, manufactured and constructed power plants totaling over 3,000 MW of gross capacity around the world. Ormat currently owns a generating portfolio of 933 MW (net), spread globally in the United States

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

(California, Nevada, Oregon, Idaho and Hawaii), Guatemala, Guadeloupe, Kenya and Indonesia. With over 72 U.S. patents, Ormat's power solutions have been refined and perfected under the most demanding environmental conditions. Ormat has been a long time partner with NV Energy and is operating several facilities under power purchase agreements.

The North Valley project will consist of a 25 MW (net) geothermal facility that will be built on private land in Washoe County, currently under lease by Ormat. Many of the production wells occupy federal ("BLM") land, also currently under lease. The project is expected to produce 217,617 MWh of renewable energy and associated PCs annually. North Valley Geothermal will utilize binary geothermal technology, which is Ormat's in-house technology, to fully utilize the geothermal resource while ensuring highest availability. The electrical generation process utilizes the geothermal brine as fuel, with the conversion to electrical energy accomplished by means of a dedicated Ormat modular geothermal power plant and a geothermal turbine. The brine and steam originate from production wells and then flow through the Ormat Energy Converter ("OEC"). At the end of the process, all of the geothermal brine is reinjected into the ground through injection wells. OEC units will use the Organic Rankine Cycle, which uses a closed loop system where the heat source is the geothermal fluid, and the motive fluid is pentane. The pentane is first preheated in the preheater before entering the vaporizer. The hot brine also flows into the vaporizer to evaporate the pentane. Afterwards, the brine flows into the preheater and exits the OEC to the re-injection wells. The pentane vapors flow onto the turbines' blades, which turn the common generator shaft to produce electricity. Next, the motive fluid vapors exit through the turbine outlet into air cooled condensers. These condense the pentane vapors into a liquid phase. Following, the condensed pentane is pumped by the feed pumps into the pre-heaters for an initial warm up. Lastly, it flows into the vaporizers to begin the cycle again. Binary geothermal facilities built by Ormat, utilizing the OEC, have proven successful for decades. With an existing Large Generator Interconnection Agreement ("LGIA"), project interconnection will be through a 57-mile 120-kV gen-tie line that is in development to be constructed as part of the project on easements already secured by Ormat in Washoe and Churchill Counties, Nevada. The gen-tie line will interconnect to NV Energy's system at the existing Eagle 120-kV Substation. Permitting for this project includes the Special Use Permits from Washoe and Churchill Counties that were issued on December 18, 2020, and October 12, 2021, respectively. The Decision Record/Finding of No Significant Impact on the Environmental Assessment from the BLM were issued on May 21, 2021.

Ormat estimates that the North Valley project will provide approximately 300 construction jobs over an 18-month construction period. After commercial operation in December 2022, the facility is expected to provide up to 20 permanent jobs with an average salary of $97,000 annually and for an estimated annual payroll of $1,940,000 and a total payroll of $48.5 million over life of the PPA. Overall, based on information provided by Ormat, the Companies estimate that the total capital investment in Nevada's economy directly associated with the North Valley project will be more than $90 million during construction and provide $15.6 million in direct economic impact in Washoe County each year in operations. Total taxes paid over a 25-year period for a 25 MW project would be approximately $23.5 million. A work site agreement or a similar document, to be executed between Ormat, on behalf of ORNI 36, LLC, and International Brotherhood of Electric Workers ("IBEW") Local Union 401 and IBEW Local Union 1245 is included as a PPA requirement and will be provided to the Companies prior to issuance of the Notice to Proceed (i.e., initial notification by Ormat to its construction contractor to commence work under the construction contract).

The PPA is with Sierra for a 25-year term at a flat energy price of $[redacted] per MWh. The project has an expected net capacity rating of 25 MW. It is expected to generate 217,617 MWh and provide 208,442 PCs annually. A copy of the PPA can be found in Technical Appendix REN-2-NV (a). Figure REN-7 shows a map of the project site.

FIGURE REN-7
NORTH VALLEY PROJECT SITE

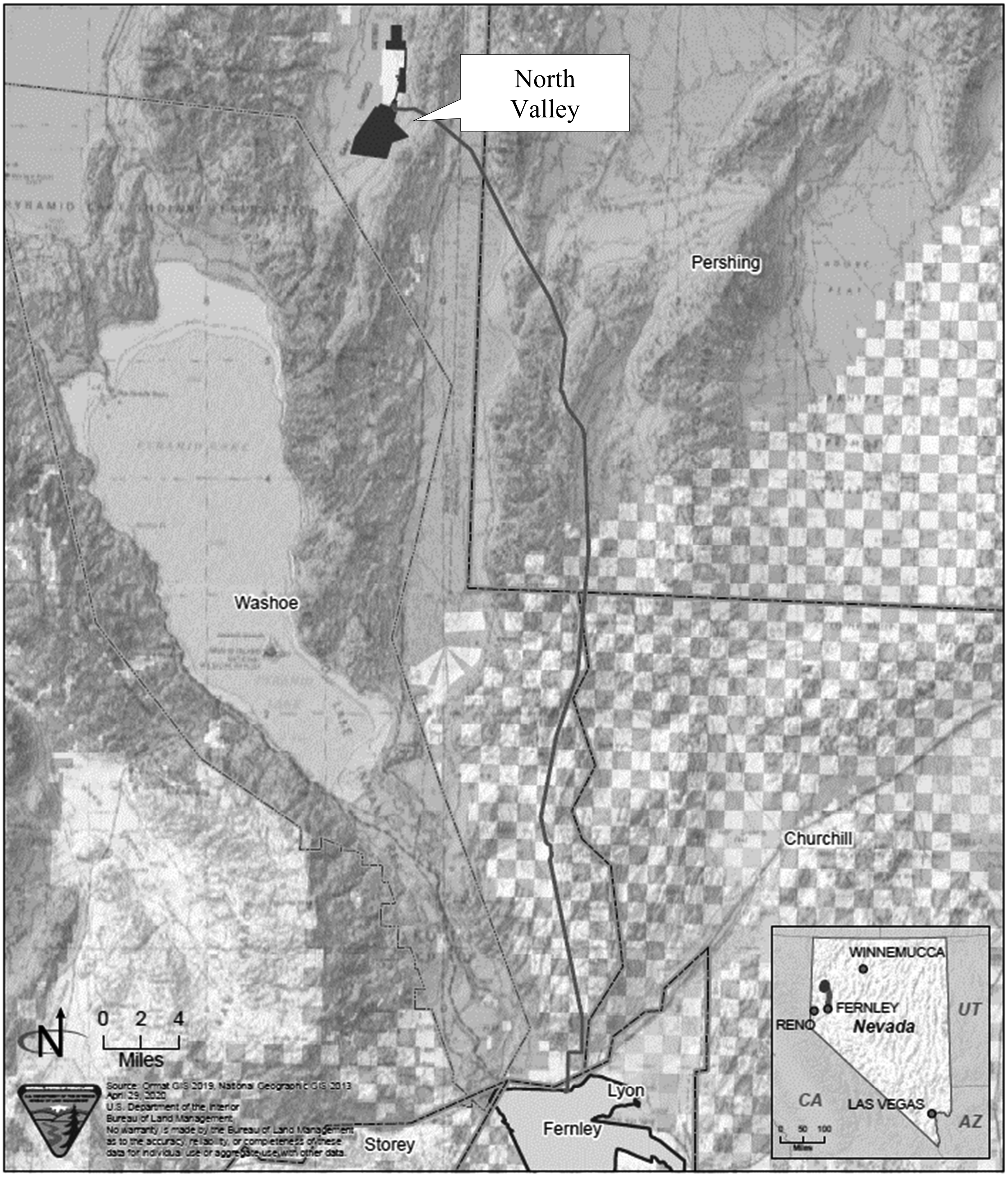

Figure A-1. Project Area

- Proposed gen-tie line
- Area of Interest
- County boundary
- Pyramid Lake Paiute Tribe Reservation Boundary

Surface Management Agency
- Bureau of Indian Affairs
- Bureau of Land Management
- Bureau of Reclamation
- Private
- Fish and Wildlife Service
- Nevada State
- Water

Technical Appendix REN-2-NV (b) contains detailed information about the North Valley project, including the information required by NAC § 704.8885 and NAC § 704.8887.

b. Reid Gardner Grid-Tied BESS

The Reid Gardner BESS will be located in Clark County, Nevada, on the site of the Companies' retired and demolished coal-fired Reid Gardner Generating Station. The 220 MW battery, with 440 MWh of storage would connect to the 230-kV Reid Gardner substation. It would be built by the battery s upplier, Tesla, under an Engineer, Procure and Construct ("EPC") contract with an anticipated commercial operation date of May 31, 2023. Nevada Power would own the facility with initial operation and maintenance contracted to be performed by Tesla.

Background:

The proposed Reid Gardner BESS is indirectly the result of the Companies' 2020 BESS RFP and is why the Companies are able to propose a project of this size while maintaining a COD that supports summer 2023 capacity needs. The Companies issued an RFP in November of 2020, which was described in more detail in Docket No. 21-06001 (the 2021 Joint IRP). The Companies filed for three BESS projects in the 2021 Joint IRP and then subsequently withdrew them, informing the Commission that they would seek to improve upon the costs and benefits of battery energy storage and return in a later filing with an enhanced proposal.[33] However, the Companies retained the available Tesla production capacity for a 440 MWh BESS and, after economic analysis that included both 2-hour and 4-hour configurations of storage at Reid Gardner, determined that the proposed Reid Gardner BESS, with a two-hour configuration, provides the lowest Present Worth Revenue Requirement compared to the alternative large capacity additions evaluated in Screening Analysis 3 in the Economic Analysis section of the narrative. Alternative site locations were evaluated prior to the economic analysis as discussed below.

In August 2020, Nevada and many other western states experienced record-breaking temperatures that caused extreme high demand on the electric system. These conditions made generation scarce across the West as utilities and other market participants worked to supply their electric demands. This scarcity of supply led to EEA and energy conservation requests in some states, including Nevada. Specifically, on August 18, 2020, the Balancing Authority ("BA") experienced a Level 3 EEA. The Balancing Authority experienced another Level 3 EEA on July 9, 2021, which is discussed in greater detail in the testimony of Mr. Ryan Atkins. As the Commission is aware, the Companies made great efforts to procure energy to meet demand and undertook public outreach asking customers to minimize energy usage during this time. The Companies are requesting approval of the Reid Gardner BESS project as part of its efforts to ensure customers are not again at risk of such severe capacity and energy shortages, and the resultant potential load interruptions.

The proposed Reid Gardner BESS is the result of intense evaluation and predevelopment efforts undertaken after withdrawing the Chukar 2, Steamboat and Brunswick projects. It incorporates a novel 2-hour duration, allowing greater capacity within the 440 MWh footprint, that provides

[33] The Companies filed for approval of the Chukar phase 2, Brunswick and Steamboat battery projects in Docket No. 21-06001.

excellent coverage for summer evening peak needs. It is located in southern Nevada close to the greatest capacity need and immune from transmission import constraints, repurposes the site of a retired coal generating station, and utilizes available transmission capacity requiring minimal interconnection cost. In addition, as a Companies-owned and grid-tied asset, its operation is not constrained by solar contract commercial terms.

Benefits:

This project will reduce reliance on market capacity and will help mitigate solar ramping impacts to the system. As the Companies become more heavily invested in solar resources, a new challenge is quickly emerging. As described in the Energy Supply Plan in the 2021 Joint IRP, with increasing amounts of renewables in the Companies' resource portfolio, the evening hours experience the capacity from the available renewable resources dropping at a faster rate than the load. The traditional peak load hours will be supplied partially by solar and the remaining peak load – the "net peak", or load less dispatch-limited resources – is a shorter duration peak. This creates a resource gap to be filled to replace the lost solar generation for a short duration of the highest need. This concept of 'net peak' (total load minus wind and solar energy) was presented in the ELCC report in the Fourth Amendment to the 2018 Joint IRP[34] and is one of the key challenges facing the Companies moving forward, and battery storage with varied durations is one solution. To ensure the Companies have adequate energy resources to meet the growing demands of their customers and maintain grid stability and reliability, the Companies need to augment their renewable energy resources with capacity. Grid-tied BESS systems offer the flexibility to store the energy that is available anytime and dispatch it when resources are needed the most.

The 2-Hour BESS addresses the very specific short duration need for capacity: however, it may not always be the optimal duration of storage. With greater penetration of BESS, longer duration storage becomes a better option. The ELCC report presents the load during peak hours as being in the shape of a pyramid, with solar production during the day compressing the net peak into a narrower pyramid. The report demonstrates that shorter duration storage has a high ELCC initially, corresponding to the narrow tip of the pyramid, but that this ELCC declines faster than that of longer duration storage.[35] The short duration 2-hour BESS proposed in this Amendment takes advantage of the narrow tip of the pyramid prior to the addition of significant additional quantities of storage resources to the portfolio.

Besides the capacity benefits, this new BESS project has several other potential benefits, including energy arbitrage (storing energy when the price of energy is low and discharging during peak pricing events), providing localized voltage support and reactive power, helping to integrate intermittent renewable resources, and improving energy quality to the local area.

This transmission grid-tied facility also offers opportunities for quick deployment of non-carbon-emitting capacity due to its minimal land requirement and interconnection facilities.

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[34] *See* Docket 20-07023, Technical Appendix ECON-5, Section 1.2.2.
[35] *Id*. Section 4.2.3.

Site Due Diligence

A rigorous vetting process was undertaken to identify potential locations that could be utilized for new BESS installations. The primary goals of this project were to place a battery in service as expeditiously as possible with permitting and development certainty, and to locate the project so that it would provide as much benefit to the grid as possible.

Each site was evaluated for issues that would limit the ability to site a BESS at the location. The first item to be considered was to identify available company-owned land that could be used to site the projects because the short timeline precluded the use of sites that would require potentially lengthy negotiations, permitting, and acquisition costs. Interconnection cost and issues were then estimated for each site. The sites were also reviewed for potential concerns that might arise with construction, permitting or neighbors. Some locations that had some positive attributes for siting a BESS also had attributes or constraints that precluded the possibility of locating a system there economically or in the timeframe needed. For example, some were in a residential area and the noise of the cooling systems would preclude them from getting permitted, or would require mitigation efforts that would increase the cost and time to construct.

The Fort Churchill Solar and Nellis Solar sites were evaluated as potential host sites since batteries located there would be eligible for the Investment Tax Credit ("ITC") with normalized treatment. Fort Churchill Solar was not selected because the increased unit cost per megawatt-hour for the storage project to modify the facility and the lack of scale, when compared to Reid Gardner, outweighed the normalized ITC benefit. More detail on the cost analysis of siting a BESS at Fort Churchill Solar is provided in confidential Technical Appendix REN-7. Nellis Solar was not selected because the lease agreement for the land would need to be negotiated with the Department of Defense which would not support the quick development schedule. Three other sites, partially developed specifically for transmission-connected batteries, were also evaluated but were eliminated due to the cost of land, the cost and timing of the transmission interconnection and the limited hosting capacity. The site evaluation and due diligence efforts led to the selection of the Reid Gardner site due to available owned land, the benefits of reusing a brownfield site, ample space for a large BESS, and transmission hosting capacity with minimal anticipated interconnection cost.

BESS Alternative Cost Comparisons

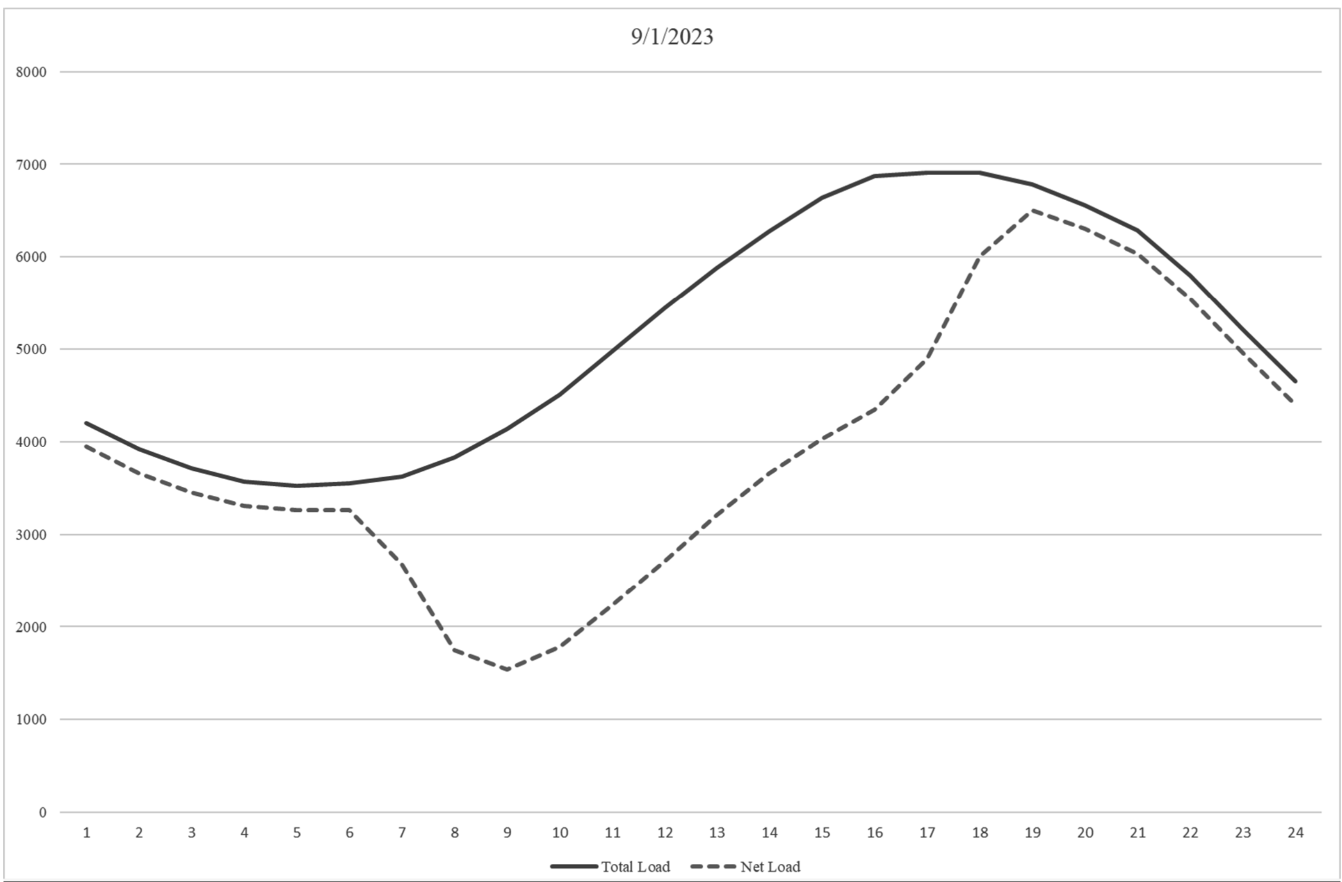
This 220 MW project is anticipated to cost $217 million. Due to the price volatility of the Lithium Carbonate used in the battery system, the EPC contract will include an index adjustment method for contract price, up or down from a baseline Lithium Carbonate commodity index price. The recent price volatility of this commodity has resulted in an industry practice that utilizes contracts with index-based price adjustments. Table REN-4 below compares the proposed Reid Gardner BESS to the three projects proposed in the 2021 Joint IRP that were expected to cost a combined $101 million. A more detailed description of the anticipated costs of the Reid Gardner BESS in both 2-hour and 4-hour configurations is provided in confidential Technical Appendix REN-6.

TABLE REN-4
COMPARISON OF REID GARDNER BESS TO PROPOSED PROJECTS IN 2021 JOINT IRP

BESS Project	Capacity	Energy	$ per kW	$ per kWh
Reid Gardner	220 MW	440 MWh	$ 987	$ 493
Chukar 2, Brunswick & Steamboat	66 MW	264 MWh	$ 1,530	$ 382

From the table above, it is clear that the shorter duration of the Reid Gardner BESS provides capacity at a much lower unit cost than the 4-hour BESS proposed in the 2021 Joint IRP. The Companies compared the costs and benefits of 2-hour and 4-hour batteries located at Reid Gardner to address the narrow summer evening Net Peak Load, illustrated in Figure REN-8 below, and found that the 2-hour BESS is a more cost-effective configuration for this use case.

FIGURE REN-8
SUMMER NET LOAD PEAK



Furthermore, the 220 MW BESS can still be used whenever needed to operate as a 110 MW by 4-hour BESS. This does not imply all future batteries should be configured this way. Rather, much like the Companies' resource portfolio that currently contains a diverse mix of baseload and peaking turbine generators, a mix of BESS configurations that include 2-hour, 4-hour and longer duration storage projects can each provide valuable system benefits.

The Reid Gardner BESS can be compared to several non-battery capacity projects that have been proposed in this Amendment and to previous capacity projects proposed and approved in the 2021 IRP as shown in Table REN-5 below. The Reid Gardner BESS is shown to be comparable to, and in some cases, a lower capacity cost (dollars per kilowatt) option than several of the Companies' turbine upgrades. The capacity cost is also comparable to that of a combined-cycle project evaluated as part of the fall 2021 Open Resource Request for Proposals. While capacity cost, dollars per kilowatt, is not the sole metric to compare project alternatives like the analysis provided in the Economic Analysis, it is an important comparison of the cost to acquire or build capacity.

TABLE REN-5
COMPARISON OF REID GARDNER BESS TO PAST PROPOSED CAPACITY PROJECTS (CAPACITY AT PEAK)

Project	Proposed	Capacity (MW)	Capacity Cost ($Million)	Capacity Cost ($/kw)
Reid Gardner Battery	Proposed 2022 IRPA	220	217.1	987
Sun Peak Wet Compression	Proposed 2022 IRPA	21	9.0	429
Peak Fire (4 CC Blocks)	Proposed 2022 IRPA	48	48.0	1,000
Lenzie Thermal Storage	Proposed 2022 IRPA	18	13.0	722
BESS – Chukar Phase 2	Proposed 2021 IRP	26	36.9	1,419
BESS - Brunswick	Proposed 2021 IRP	30	45.5	1,517
BESS - Steamboat	Proposed 2021 IRP	10	19.3	1,930
Lenzie Turbine Upgrades	Approved 2021 IRP	40	52.7	1,318
Tracy Turbine Upgrades	Approved 2021 IRP	36	53.0	1,472
Silverhawk Turbine Upgrades	Approved 2021 IRP	40	30.4	760
Silverhawk Wet Compression	Approved 2021 IRP	30	10.0	333
Harry Allen	Approved 2021 IRP	45	48.3	1,073

c. White Pine Pumped Storage Hydro ("White Pine")

To diversify the Companies' energy storage portfolio, help integrate increasing amounts of solar energy on the system, and to prepare for other potential intermittent renewable projects such as wind, the Companies are requesting approval to investigate constructing a 1,000 MW pumped storage hydroelectric energy storage facility that has enough energy storage to supply the rated capacity for eight hours. The project will be located approximately eight miles north of Ely in White Pine County and will interconnect at the Robinson Summit Substation, allowing the project to serve both service territories. The project is being developed by rPlus Hydro a subsidiary of rPlus Energies, a Gardner Company, which is one of the largest real estate developers in Utah. Since 2018, rPlus established a portfolio of over 30 projects across the U.S. representing over 10 gigawatts of new renewable energy capacity. Along the way, rPlus executed over 630 MW of corporate renewable PPAs. rPlus Hydro has been involved in U.S. pumped storage development since 2009 and has ten pumped storage hydro projects in various stages of development in the United States.

The Companies are requesting approval to spend $3.5 million to study the White Pine project: (1) [redacted] in direct support of project development which would be paid to rPlus through a Development Services Agreement ("DSA") that would also provide the Companies the exclusive right to acquire the project, and (2) [redacted] for the Companies to support its independent project due diligence, technical review of rPlus activities, and negotiation of project design, procurement, construction agreements and related documents.

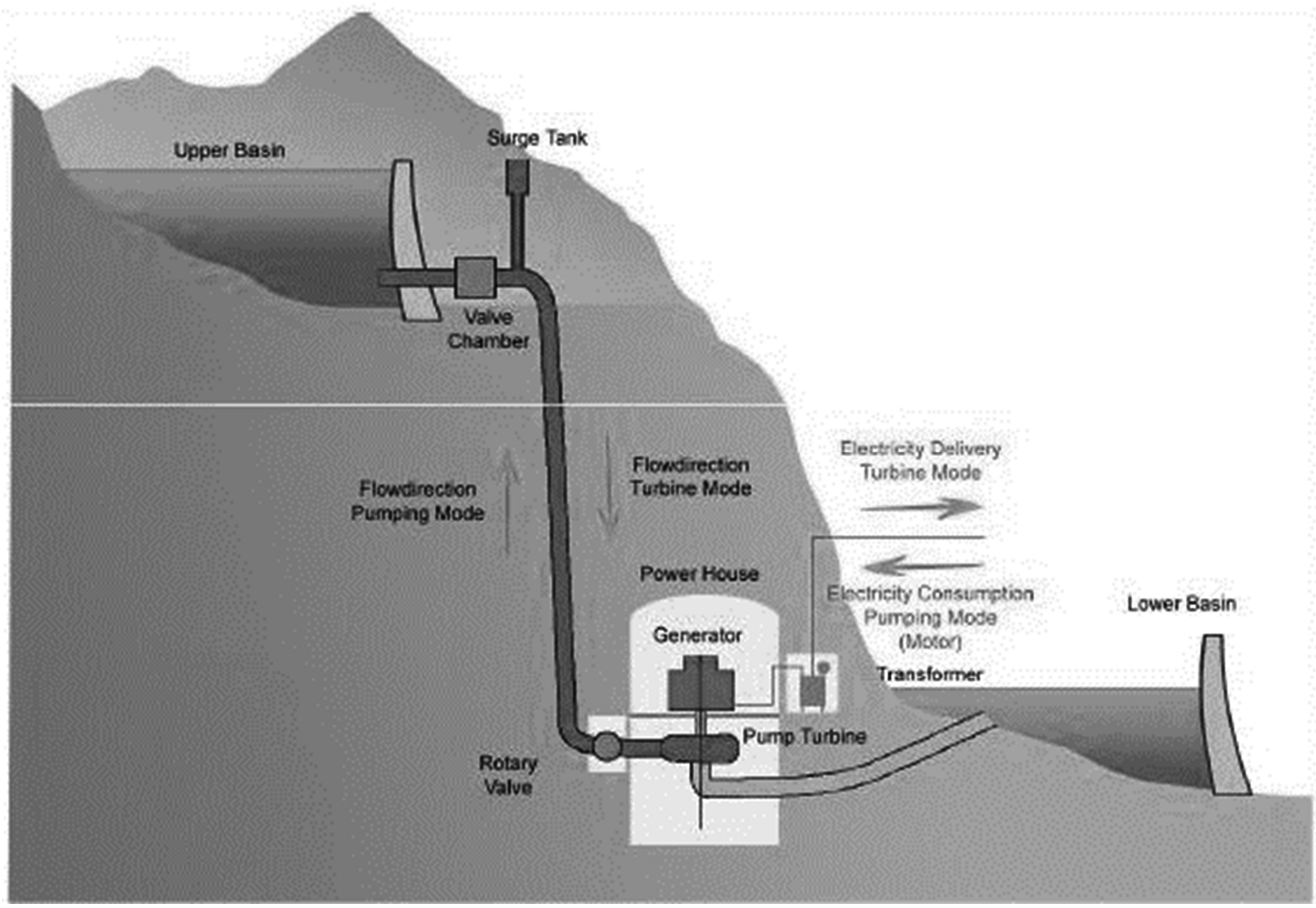
White Pine will consist of an upper reservoir with a footprint of 65 acres, formed by a 170-foot lined rockfill dam and having a working volume of 4,100 acre-feet. The lower reservoir will have a footprint of 90 acres, formed by a 134-foot lined rockfill dam and have a working volume of 4,100 acre-feet. There will be a vertical headrace shaft that connects the two impoundments that will be approximately 2,270 feet high and 20 feet in diameter, leading to a horizontal headrace tunnel 280 feet in length and 20 feet in diameter. A powerhouse is anticipated to be located in a constructed underground cavern measuring 362 feet in length and with a 78-foot span, with an adjacent transformer chamber. From the powerhouse, a tailrace tunnel that is 7,380 feet in length and 20 feet in diameter will lead to the lower reservoir. Access to the powerhouse will be through a 5,250 feet-long access tunnel. The energy created by the generators will be directed through a cable (transmission) tunnel 4,500 feet in length to a surface switchyard and then to a 28-mile, 345-kV transmission line on an H-frame tower, leading to the point of interconnection at the Robinson Summit Substation.

The White Pine facility will have a generating and pumping capacity of 1,000 MW. The project will utilize three 333.3 MW generating/pumping units, which will provide a wide operating range whether in the generating or pumping (charging) mode. The project will investigate the utilization of variable-speed equipment which would allow an even wider range of operation in pumping mode and enhanced ancillary services. Response times will be at the millisecond level if a variable speed pumping system is used, and in the range of seconds for fixed-speed units. The project will be sized to have an eight-hour storage duration at full output, with the ability to generate for significantly longer durations at lower output levels. The project will require ten hours to fully fill (re-charge) at its maximum pumping rate if the upper reservoir is depleted.

<u>Technology Discussion</u>

Pumped storage hydro is a proven form of utility-scale, long-duration energy storage. In a pumped storage plant, surplus or lower-value electrical energy is used to pump water from a reservoir at lower elevation to a reservoir at higher elevation. Energy is stored in the form of the gravitational potential of the water in the upper reservoir. When power is needed, water is released from the upper reservoir through the powerhouse, generating power, and then back into the lower reservoir. A typical pumped storage hydro facility is depicted below in Figure REN-9.

FIGURE REN-9
TYPICAL PUMPED STORAGE HYDRO ARRANGEMENT



Until recently, pumped storage was virtually the only form of utility-scale energy storage employed in the US and around the world. The only other technology used at scale was Compressed Air Energy Storage ("CAES"), which has two operating plants in the world, with respective sizes at 290 and 110 MW. CAES projects require uncommon geological formations for the underground air cavern, so CAES is an option available to very few utilities. Established CAES technology also involves the combustion of natural gas, which results in greenhouse gas emissions. Other long-duration energy storage technologies — hydrogen-based systems and mechanical systems like rail energy storage and systems that lift and lower concrete blocks — are generally at the demonstration or research and development stage and do not represent commercially available alternatives to the White Pine. PSH compares favorably to BESS for longer duration applications due to its longer life cycle, lack of capacity degradation, preservation of energy when kept at high storage levels for long durations, lower carbon footprint and is comparable in cost to BESS. As shown in confidential Technical Appendix REN-10, White Pine compares well to BESS on the basis of cost per unit of energy. If approved, the $3.5 million expenditures will help refine and add certainty to the current cost estimate to help confirm that the addition of PSH, besides all the other benefits listed below, will be the most cost-effective solution to provide long-duration storage. Making a cost comparison between these two technologies presents many challenges because of the long operating life of pumped storage hydro facilities, since they will have a book life of 50 or 60 years and they can continue to operate for over 100 years with life extension activities. Utility-scale battery storage is still a nascent industry though the technology is progressing very rapidly. Making estimations of the cost and performance of these systems decades in the future requires making some assumptions with a degree of uncertainty. This uncertainty could result in large swings in future pricing estimations. In Technical Appendix REN-10, a 60-year life-cycle cost comparison between a 1,000 MW PSH facility is made to a 100 MW BESS facility to achieve a rough comparison. Three scenarios were used for the BESS 60-year life-cycle cost projection. In the best-case scenario, the cost of BESS system re-builds is declining over time. In the second projection, the cost is remaining flat. Finally, in the worst-case scenario, the cost of BESS systems will rise over time. At the current time, BESS systems are optimized for two- to four-hour operation, and, thus, an assumption is made that an eight-hour operating duration will be available in 2032. This cost comparison shows that the energy storage cost is close enough between BESS and pumped storage hydro to warrant further exploration of a pumped storage hydro project.

Like BESS, PSH systems represent dispatchable capacity that helps to integrate carbon-free renewable resources. NV Energy's resource plan anticipates deployment of thousands of MW of BESS, stand-alone and paired with renewables, as presented in the 2021 Joint IRP and shown in Figure EA-3, Section 8 of this filing. Figure EA-3 provides a summary of the size of energy storage that is projected to be needed through 2041 as well as when it is projected to be constructed. While PSH projects are faced with a longer and more challenging development timeline, they have substantial advantages compared to BESS:

- longer durations of storage, with longer duration becoming increasingly important as renewable energy penetration increases;
- significantly longer useful life than any BESS system available today;
- PSH capacity does not experience degradation like BESS does;
- more mature technology compared to BESS;
- avoids supply risks associated with competition for materials such as lithium and international political considerations (e.g., reliance on raw materials and manufacturing in China);
- PSH has a lower cradle-to-grave carbon footprint than BESS as shown in Figure REN-10 below.

FIGURE REN-10
CARBON FOOTPRINTS OF RENEWABLE AND STORAGE TECHNOLOGIES[36]

Table 1. Median Published Life Cycle Emissions Factors for Electricity Generation Technologies, by Life Cycle Phase

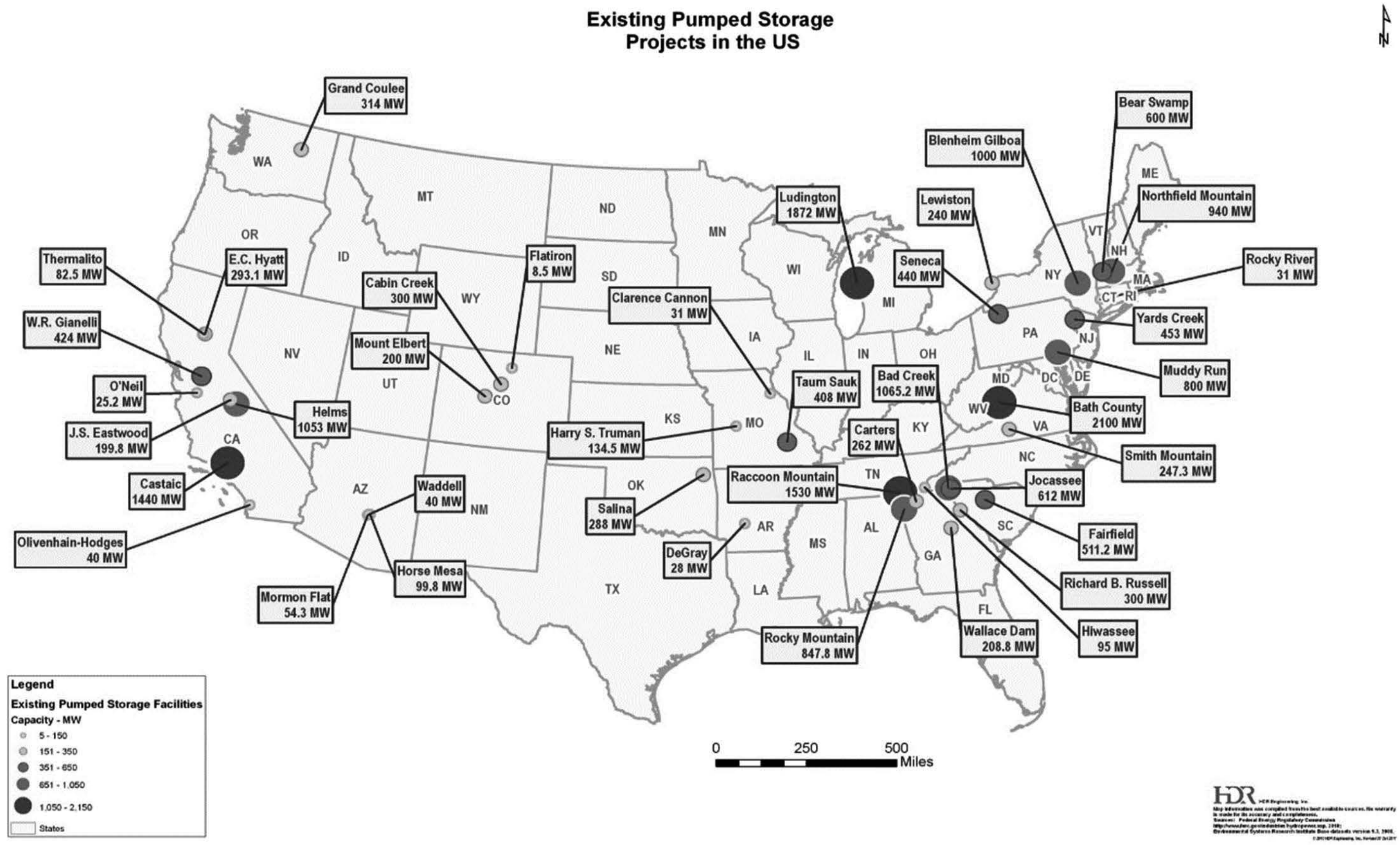
	Generation Technology	One-Time Upstream	Ongoing Combustion	Ongoing Non Combustion	One-Time Downstream	Total Life Cycle	Sources
Renewable	Biomass	NR	—	NR	NR	52	EPRI 2013 Renewable Electricity Futures Study 2012
	Photovoltaic[a]	~28	—	~10	~5	43	Kim et al. 2012 Hsu et al. 2012 NREL 2012
	Concentrating Solar Power[b]	20	—	10	0.53	28	Burkhardt et al. 2012
	Geothermal	15	—	6.9	0.12	37	Eberle et al. 2017
	Hydropower	6.2	—	1.9	0.004	21	DOE 2016
	Ocean	NR	—	NR	NR	8	IPCC 2011
	Wind[c]	12	—	0.74	0.34	13	DOE 2015
Storage	Pumped-storage hydropower	3.0	—	1.8	0.07	7.4	DOE 2016
	Lithium-ion battery	32	—	NR	3.4	33	Nicholson et al. 2021
	Hydrogen fuel cell	27	—	2.5	1.9	38	Khan et al. 2005
Nonrenewable	Nuclear[d]	2.0	—	12	0.7	13	Warner and Heath 2012
	Natural gas	0.8	389	71	0.02	486	O'Donoughue et al. 2013
	Oil	NR	NR	NR	NR	840	IPCC 2011
	Coal	<5	1010	10	<5	1001	Whitaker et al. 2012

While BESS systems are the most likely alternative to the White Pine project in terms of addressing utility and market needs in the emerging low-carbon market, the advantages afforded by pumped storage make the White Pine an exceptional opportunity for meeting system needs, while diversifying the Companies' energy storage portfolios.

Figures below provide general information regarding pumped storage hydro. Figure REN-11 shows existing pumped storage hydro projects in the United States. Figure REN-12 shows further information for existing pumped storage hydro projects in the United States including capacity and location in graph form.

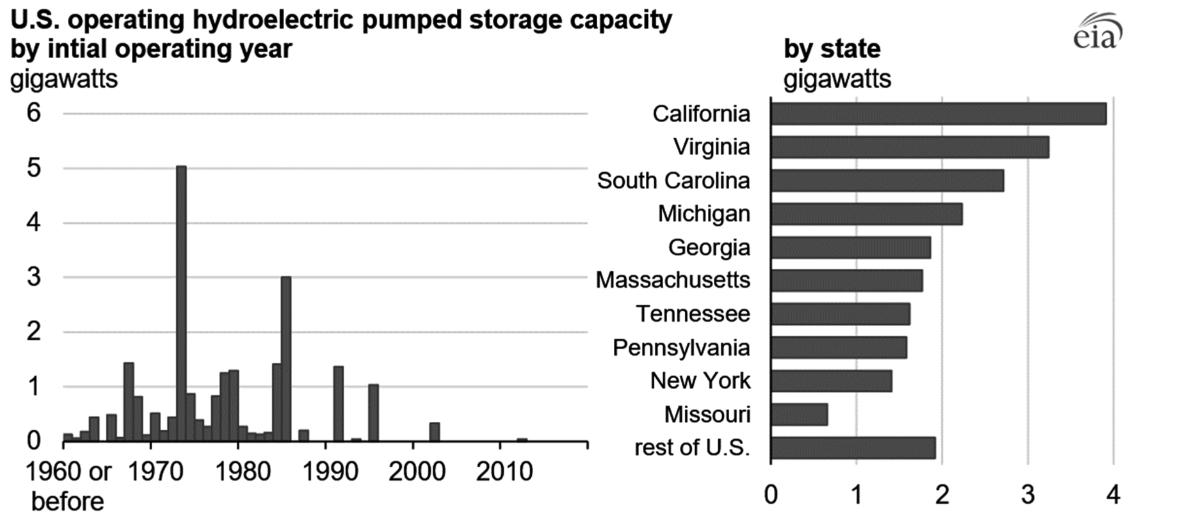
[36] Life Cycle Greenhouse Gas Emissions from Electricity Generation: Update (nrel.gov). NR = Not Reported

FIGURE REN-11
EXISTING PUMPED STORAGE PROJECTS IN THE US[37]



37 Northwest Power and Conservation Council, *Pumped Storage – The Proven Grid Scale Storage Solution*, (Slide 9), January 27, 2015, available at https://www.nwcouncil.org/sites/default/files/overview_pumpedstorage.pdf.

FIGURE REN-12
EXISTING PUMPED STORAGE PROJECTS IN THE US[38]



Source: U.S. Energy Information Administration, *Annual Electric Generator Report*

<u>Project Development Agreement</u>

The Companies are negotiating a DSA with rPlus under which rPlus continues to lead the development of the White Pine with a [redacted] contribution from the Companies. In return for that investment, the Companies receive the exclusive right to acquire the project. The Companies will also conduct due diligence in parallel with the work done by rPlus. This due diligence is estimated at [redacted] and will include independent engineering reviews, engineering studies and permitting reviews.

Should the Companies unilaterally decide to cease participation in the project, the Company would investigate selling their rights to the project to another off-taker or energy supply company to recoup as much of the investment that was made in the project as is possible.

The Companies will return to the Commission to seek full approval of the White Pine should this initial development phase indicate that the project is both feasible and cost effective.

<u>White Pine PSH Cost Comparison</u>

The Companies sought Commission approval to pursue PSH technology several years ago, and, for multiple reasons, the request was not approved.[39] This filing is different for several reasons:

[38] U.S. Energy Information Administration, Annual Electric Generator Report, also available at https://www.eia.gov/todayinenergy/detail.php?id=41833 (Today in Energy, *Most pumped storage electricity generators in the U.S. were built in the 1970s*.).

[39] Docket No. 10-02009, Application of Nevada Power Company d/b/a NV Energy for approval of its 2010-2029 Triennial Integrated Resource Plan.

1) the Companies will continue to have a capacity open position,[40] 2) the need for storage diversity is prudent due to uncertain market forces and limited history on the long-term performance of contracted battery systems, 3) White Pine PSH is a more mature project from the perspective of project development, and 4) the anticipated cost on a dollar per unit of energy of the White Pine project is similar or better than that of BESS. Current estimated cost of the White Pine is [redacted] and is compared to BESS projects in Table REN-6 below. In the comparison in Table REN-6, the initial cost to install a PSH project is high compared to batteries on a dollar per kW basis but is a lower cost alternative on a dollar per kWh basis, making it a suitable resource for shifting the delivery of large amounts of intermittent renewables to times when most needed. The Reid Gardner Project is a two-hour energy resource and the Chukar 2, Brunswick & Steamboat projects are four-hour projects, while the White Pine is an eight-hour project. The battery systems presented below will also need to have augmentations to maintain their initial capacity and will be replaced multiple times in the 60-year book life for the White Pine. Additionally, life extension activities for the White Pine can extend the useful lifespan to over 100 years.

TABLE REN-6
COMPARISON OF WHITE PINE TO BESS

Energy Storage Project	Capacity	Capital Cost	Energy	$ per kW	$ per kWh
Reid Gardner	220 MW	$217 m	440 MWh	$ 987	$ 493
Chukar 2, Brunswick & Steamboat	66 MW	$101 m	264 MWh	$ 1,530	$ 382
White Pine	1,000 MW	[redacted]	8,000 MWh	[redacted]	[redacted]

[40] *See* Figure EA-17; the Loads and Resources Table, Preferred Plan for 2022-2041, Section 8 of the narrative. (Economic Analysis).

SECTION 7. TRANSMISSION PLAN

A. Introduction

The regulations governing integrated resource planning require that the Companies include in their triennial IRPs a 20-year plan to meet the transmission needs of native load customers, and service requests from third parties.[41] The transmission plan is built upon the load forecasts, system characteristics, existing and future transmission facilities and obligations as described in the transmission plan section filed in Docket No. 21-06001. Based in part on these key system characteristics, the transmission plan examines the capabilities of the existing transmission system in order to determine the need for and timing of any additional transmission facilities. This amendment proposes two additions to the transmission plan presented in Docket No. 21-06001. These additions include:

1. The LGIA for the North Valley Geothermal project.

2. The LGIA for the BESS located at the Reid Gardner Substation and approval of the required network upgrades.

For informational purposes only, the Companies are also providing a description of proposed revisions to the LGIA for the Hot Pot 350-MW renewable generation project at North Valmy Generating Station ("Valmy") that remove the requirement for a 345 kV transmission line network upgrade and add a Remedial Action Scheme ("RAS") at Valmy.

B. Specific Requests for Commission Approval for New Transmission Projects

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

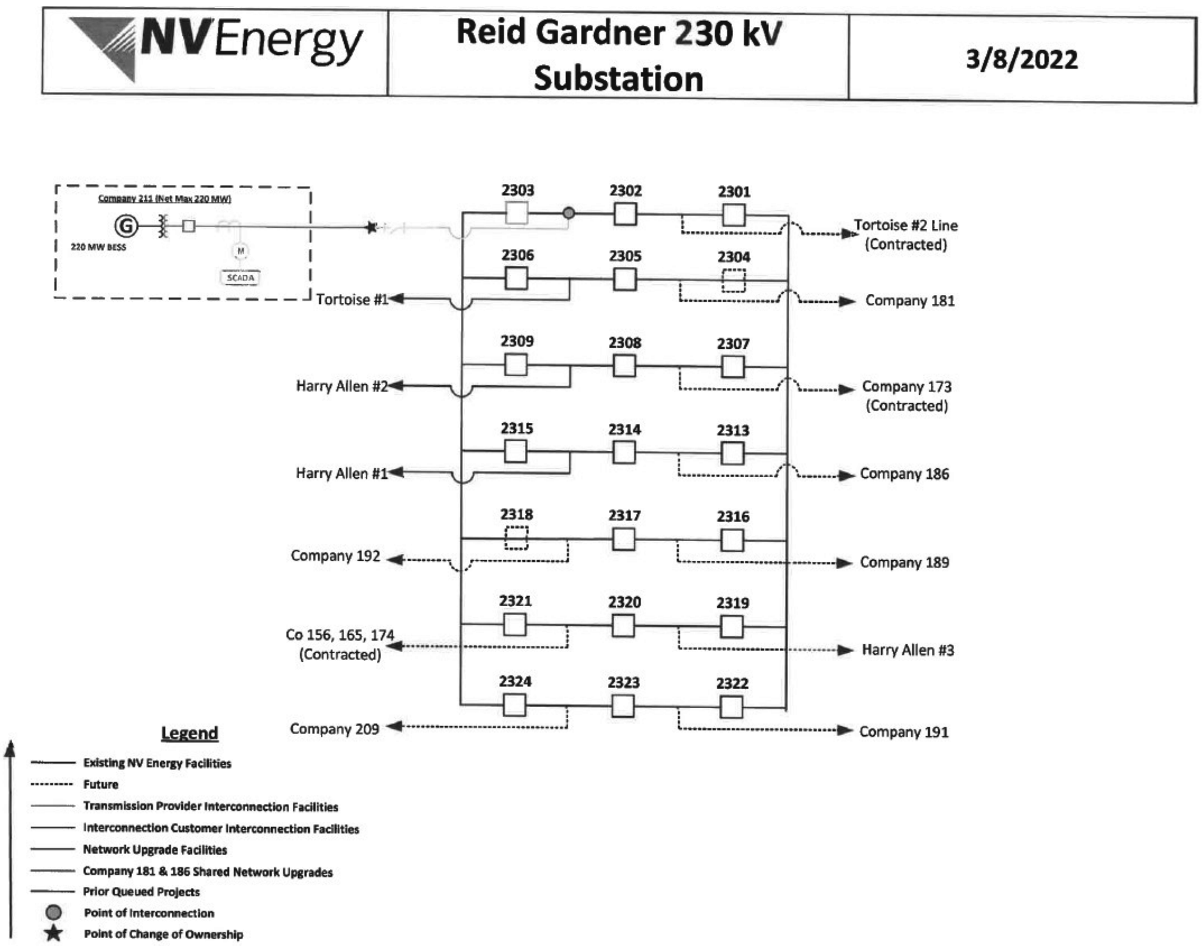
The Companies are requesting Action Plan approval to begin network upgrades required to support the development of the Reid Gardner BESS (220 MW at Reid Gardner 230 kV Substation. Nevada Power was requested to provide interconnection and necessary network upgrades at the Reid Gardner 230-kV Substation to support the addition of the Reid Gardner 220 MW BESS. The proposed in-service date for this project is April 12, 2023. The Provisional Interconnection System Impact Study ("PSIS") for this project is included in the Technical Appendix Item TRAN-2.

[41] *See* NAC § 704.9385(3).

In addition, the Companies are providing a description of the Network Upgrades required for the North Valley Geothermal Project (45 MW at Eagle 120 kV Substation) but are not requesting Commission approval of the Network Upgrades because all facilities are below 200 kV.

Construction Scope: Nevada Power will construct the facilities required to accommodate the new Reid Gardner 230 kV terminal position at the existing Reid Gardner 230 kV Substation, including required substation upgrades to accommodate the interconnection. Figure TP-1 below depicts a single-line diagram of the proposed project.

FIGURE TP-1
ONE-LINE DIAGRAM OF REID GARDNER BESS (COMPANY 211)



Contingent facilities:

Contingent Facilities are unbuilt Interconnection Facilities and/or Network Upgrades upon which the cost, timing and study findings for Interconnection Customer's Interconnection Request are dependent. The Contingent Facilities for this request include:

1. 230 kV bus and breaker additions for the second line to Tortoise Substation - Planned in service summer of 2022 pursued by NV Energy.

Requirements for provisional interconnection service:

1. The following Interconnection Facilities are completed and in service as part of the Companies' LGIA:
    a. Metering;
    b. Telecommunications;
    c. Reid Gardner 230-kV terminal addition and substation entrance; and
    d. All associated Transmission Provider Interconnection Facilities.

Cost responsibility:

Nevada Power's cost responsibility pursuant to the OATT is shown in Figure TP-2.

FIGURE TP-2
NEVADA POWER'S COST RESPONSIBILITY[42]

NEVADA POWER'S COST RESPONSIBILITY						
	Total **$MM**		**Network Upgrades** **$MM**	**Distribution Upgrades** **$MM**	**TPIF** **$MM**	**LGIA Section 5.13 Direct Assign** **$MM**
Substation						
Reid Gardner 230 kV Terminal Addition, 1 Breakers	0.400		0.400			
Transmission Lines						
230 kV Substation Entrance	1.500				1.500	
Communications/Protection/Metering						
Lead Line Protection Facilities and Review	0.100				0.100	
Co 211 Site Communications	0.250				0.250	
Harry Allen 230 kV Communications	0.100				0.100	
Metering						
230 kV site metering	0.125				0.125	
Lands/Permitting/Right-of-Way						
Lands and environmental permitting support	0.025					0.025
Total:	**2.5**		**0.400**		**2.075**	**0.025**

[42] While Nevada Power is responsible for all costs depicted in Figure TP-2, its costs responsibility for the Network Upgrades and TPIF will be accounted separately. Nevada Power is responsible for the Network Upgrades as the transmission provider and for TPIF as the interconnecting customer.

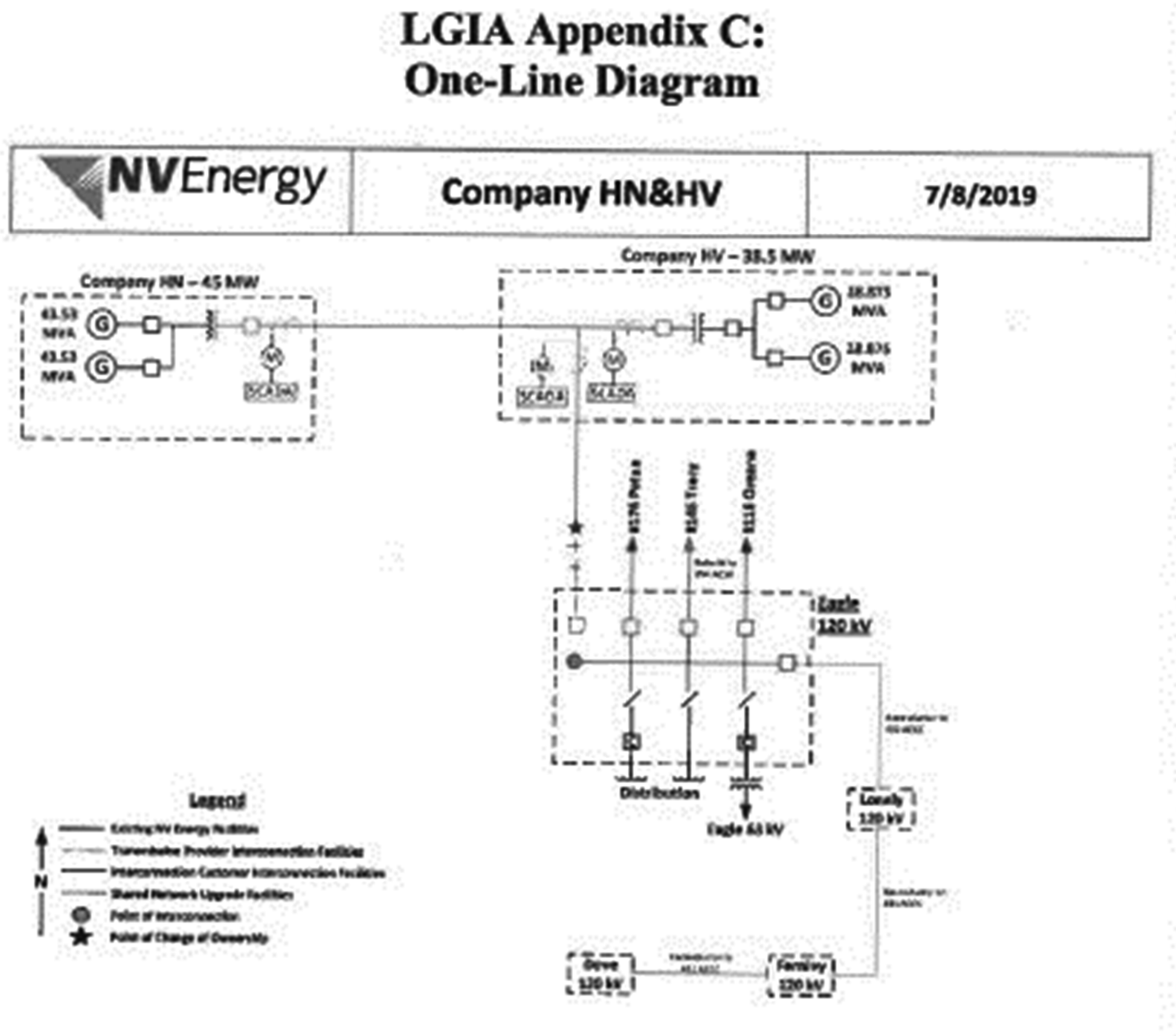
C. Network Upgrades Required for the North Valley Geothermal Project (Company HN)

ORNI 36, LLC ("Ormat")[43] has requested Sierra provide interconnection and necessary network upgrades at the Eagle 120 kV Substation to support the addition of its North Valley geothermal project, a 45 MW geothermal generating facility. The North Valley geothermal project is a two-phase project, with the first phase building the project out to 25 MW. Ormat submitted the North Valley geothermal project in response to the Companies' 2021 renewable request for proposals. The proposed in-service date for this project is December 2022. The LGIA for this project is included in the Technical Appendix Item TRAN - 1.

<u>Construction Scope</u>: Sierra will construct the facilities required to accommodate the new Eagle 120 kV terminal position at the existing Eagle 120 kV Substation, including required substation upgrades to accommodate the interconnection. Figure TP-3 below depicts a single-line diagram of the proposed project. In addition, there are shared network upgrades with two other projects, designated as "company HO" and "company HV."

[43] "Ormat" and "Company HN" are used interchangeably.

FIGURE TP-3
ONE-LINE DIAGRAM OF NORTH VALLEY (COMPANY HN)
GENERATION INTERCONNECTION



<u>Budget and Cost Responsibility</u>: Ormat is responsible for the cost of building the new terminal position at the existing Eagle 120-kV Substation, its generator, lead line, and associated interconnection facilities, including required communications, protection and metering facilities. Sierra is responsible for the cost associated with Network Upgrades, per the OATT. There are no individual Network Upgrades, only Shared Network Upgrades. Shared Network Upgrades include rebuilding the #146 and #118 lines, and reconductoring and adding Optical Ground Wire ("OPGW") to the #113 and #190 lines with an estimated cost of approximately $17.410 million. The cost of these network upgrades is shared with companies HO and HV. Shared Network Upgrades will be secured on a pro-rata basis based on requested interconnection megawatt amount among participants in the 2017F N-2.0 Rural North Cluster Study. If any of the Cluster Participants change status, a re-allocation of the Shared Network Upgrade costs will be completed, and a formal letter will be issued notifying the remaining participant(s) of their new pro-rata cost allocation of the Shared Network Upgrades. Projected Network Upgrades cost sharing is shown in Figure TP-

4 below. Ormat, as an Interconnection Customer, shall provide security/collateral pursuant to Article 11 of the LGIA and Attachment L of the OATT for its pro-rata share of the Shared Network Upgrades in the amount of $5,677,000. Transmission Provider shall pursue the OPGW on the #113 and #190 lines unsecured by the Interconnection Customer, due to additional modifications to the scope after the Generator Interconnection Agreement is executed.

FIGURE TP-4
PROJECTED NETWORK UPGRADE COST SHARING

Shared Network Upgrades	**Company HN's Share $M**	**Company HO's Share $M**	**Company HV's Share $M**	**Total Estimate $M's**
MW	**45**	**45**	**38.5**	**128.5**
Pro-Rata Share Percentage Allocation	**35%**	**35%**	**30%**	**100%**
#146 Line Rebuild OPGW	$0.527	$0.527	$0.451	$1.505
Eagle Sub Equipment Uprate	$0.044	$0.044	$0.037	$0.125
Fernley Sub Equipment Uprate	$0.005	$0.005	$0.004	$0.015
Lonely Substation Equipment Uprate	$0.007	$0.007	$0.006	$0.020
Rebuild #146 Line	$3.075	$3.075	$2.631	$8.780
#118 Line Rebuild Double Circuit (first 2 miles)	$1.68	$1.68	$1.44	$4.800
Reconductor #113 Line	$0.620	$0.620	$0.530	$1.770
Reconductor #190 Line	$1.399	$1.399	$1.197	$3.995
OPGW for #113 line	$0.110	$0.110	$0.009	$0.310*
OPGW for #190 line	$0.310	$0.310	$0.270	$0.890*
TOTAL	**$6.097**	**$6.097**	**$5.217**	**$17.410**

Ormat shall securitize 100 percent of the Shared Network Upgrades, or the full $1,003,000 listed in Figure TP-5, since the upgrade is required for the first-in-time interconnection customer.

FIGURE TP-5
FIRST IN TIME SHARED NETWORK UPGRADES

SHARED NETWORK UPGRADES		
Project Component	**Scope Description**	**NU $M's**
Substation/Protection	Eagle Control Enclosure	$1.003
	TOTAL	**$1.003**

Provisional Interconnection Service Specifications.

Due to the outages required to complete the upgrades identified for North Valley geothermal project's interconnection that could impact transmission capacity, Ormat requested to potentially interconnect the project under Provisional Interconnection Service, provided its interconnection facilities and Eagle Substation upgrades are completed. Provisional Interconnection Service offers no guarantee of capacity. Any transmission capacity that may exist would be offered on an "as available" basis but there is no capacity that can be offered on a firm basis at this time. Ormat may request, at its sole cost, quarterly studies to be completed to update the amount of Provisional Interconnection Service until the full interconnection service may be provided.

The Transmission Provider's Interconnection Facilities ("TPIF") and Shared Network Upgrade facilities listed in Figure TP-6 will be completed by October 1, 2022,[44] for Provisional Interconnection Service. Ormat is responsible for the cost of the interconnection facilities listed in Figure TP-6.

[44] This completion date is identified to meet the December 2022 project in-service date.

FIGURE TP-6
PROVISIONAL INTERCONNECTION FACILITIES

COMPANY HN INTERCONNECTION FACILITIES	
Project Component	**Scope Description**
Communication	Customer's Site Communications
	Eagle Communications to integrate Customer's communication and OPGW
Metering	High side metering at Generator site
Substation/Protection	Lead line protection Facilities
	Eagle 120 kV radial terminal addition
Transmission Lines	Substation Entrance

COMPANY HN SHARED NETWORK UPGRADE COSTS		
Project Component	**Scope Description**	**$M**
Substation/Protection	Eagle Control Enclosure	$1.003
	TOTAL	**$1.003**

D. Revisions to the LGIA for the Hot Pot Renewable Energy Project

In Docket No. 21-06001, NV Energy requested Action Plan approval to begin network upgrades required to support the development of the Hot Pot 350 MW solar generation project connected at the Valmy 345 kV Substation bus. The Companies also informed the Commission that NV Energy intended to file a non-standard Designated Network Resource ("DNR") with FERC to implement a transitional interconnection approach. This approach would ensure that total generation supplied at the Valmy Substation remains within the 800 - 875 MW capacity limit to avoid the need for the $48.04 million Falcon – Coyote Creek 345 kV transmission line that was identified as a required network upgrade in the Hot Pot LGIA. The Commission found NV Energy's proposed transitional approach as a reasonable approach to ensure transmission reliability while reducing costs to Sierra's ratepayers.[45] The Commission ordered that, within 30 days of FERC issuing its finding, NV Energy shall inform the Commission of FERC's decision regarding the non-standard DNR request by filing a compliance in Docket No. 21-06001.[46]

Since the order was issued in Docket No. 21-06001, NV Energy has determined that a preferred approach to avoid the need for the $48.04 million transmission network upgrades is the installation of a RAS at Valmy rather than implementing the non-standard DNR. This installation of the RAS

[45] Docket No. 21-06001, Modified Final Order at para. 85.
[46] *Id*.

has the advantage that it is not necessary to limit total Valmy generation to 800-875 MW. With the RAS, Valmy Units 1 and 2, Iron Point and Hot Pot may all operate simultaneously at full output, which will eliminate the potential need to curtail Hot Pot generation. In addition, it is easier for Grid Operation to operate the system since there is no need to monitor the level of total Valmy generation resulting in less potential for error and more reliable system operation. NV Energy also believes that this approach is consistent with the Commission's finding that Valmy 1 should be available to contribute to NV Energy's resource adequacy and for the benefit of its customers. As a result of the RAS, there is no need to file a non-standard DNR with FERC.

The Valmy RAS will be designed to mitigate the potential overload of the #155 Coyote Creek-Bell Creek 120 kV transmission line for an outage of the #3424 Valmy-Falcon 345 kV transmission line when there is a high level of generation at Valmy. If an outage of the Valmy-Falcon 345 kV transmission line occurs that results in an overload of the Coyote Creek-Bell Creek 120 kV transmission line, a ramp down signal will be sent to Hot Pot. If the ramp down fails to relieve the overload within the required time frame, a trip signal will be sent to Hot Pot.

The estimated cost to install the Valmy RAS is $0.5 million, however, the Companies are not requesting Commission approval of the RAS. As noted above, this is being provided for informational purposes only and to provide notice to the Commission that the Companies will not be seeking a non-standard DNR with FERC, as they discussed in Docket No. 21-06001.

SECTION 8. ECONOMIC ANALYSIS

A. Overview

Less than a year ago, the Commission accepted the Companies' Preferred Plan in its 2021 Joint IRP ("2021 Preferred Plan"), which increased the operating flexibility of some of the Companies' existing generating facilities, aggressively added renewable resources to assist the state in meeting its carbon reduction goal by 2050 and provided for new generation to replace the Valmy coal-fired station by 2025. What is driving the need for this amendment is increasing concern regarding the availability and deliverability of market purchases required to close the open position. As a result, the case development for this Amendment concentrated on reducing the Companies' open position with resources within its balancing authority area ("BAA").

Economic analyses of different capacity and energy supply plans were conducted and a Preferred Plan was selected from the set of cases. In this section, the following economic analysis topics will be covered:

- The Analysis Methodology;
- Updates to Key Modeling Assumptions;
- Assessment of Need;
- Plan Development;
- Economic Analysis Results;
- Loads and Resources Tables;
- Environmental Externalities and Economic Benefits to the State;
- Selection of the Preferred Plan.

B. Analysis Methodology

Loads & Resources Tables. The Companies' analysis of future resource requirements begins with the Loads and Resources ("L&R") tables. The long-term load forecast, planning reserve requirements, and a forecast of an annual peak capacity for supply-side and demand-side resources approved in the 2021 Joint IRP were used to determine the Companies' annual open capacity position ("Open Position"). The Open Position is defined as any value resulting from the peak load plus planning reserves being greater than the sum of the peak capacities for supply-side and demand-side resources. In accordance with the Stipulation accepted in Phase 2 of the 2021 Joint IRP, the annual peak capacity for supply-side resources is reduced by 90 MW to account for reserves held for unbundled OATT customers.

The Companies may leave some of the Open Position to be filled with market purchases for capacity and energy. In any year where there is an Open Position, the Companies will secure the needed capacity from the electric wholesale market at the forecasted capacity cost for that year. The cost of this capacity is included in the total costs for each plan. A more detailed discussion around the creation and use of the L&R tables is described in the L&R Section (part G) of this Economic Analysis narrative.

Production Costs and Capital Expense Recovery Models. After developing the L&R tables, the Companies utilize additional software tools to evaluate each plan over the planning period. The first is a production cost model known as PROMOD.[47] PROMOD computes overall production cost by performing hourly, chronological economic unit commitment and dispatch of the Companies' electric production resources and market purchases to satisfy load requirements in a least-cost solution over the planning period. A more detailed description of PROMOD can be found in Technical Appendix ECON-2. There are several key modeling assumptions made in performing PROMOD analysis. Key assumptions, including updates from the assumptions used in the 2021 Joint IRP, are discussed in more detail in the next section. The key assumptions include, but are not limited to:

a) Area configuration;
b) Hourly load forecast;
c) Market fundamentals;
d) Existing generation operating characteristics and costs;
e) Planning reserves;
f) Purchase Power Agreements – including Renewables;
g) Battery Modeling;
h) Transmission limits; and
i) Resource Buildouts.

The second model used to evaluate alternative plans is a spreadsheet workbook called the Capital Expense Recovery model ("CER"). The CER calculates annual revenue requirements associated with capital investments needed to satisfy load requirements during the planning period for each plan. Several key modeling assumptions made in the CER include, but are not limited to:

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

[47] PROMOD is a proprietary software product that the Companies license from Ventyx, an ABB Company.

Present Worth of Revenue Requirement. After running PROMOD and the CER, the sum of the annual production costs from PROMOD plus the sum of the annual capital revenue requirement from the CER over the planning period, discounted by each company's weighted cost of capital, provide the Present Worth of Revenue Requirement ("PWRR") for the various plans. A comparison of the PWRRs of each plan provides a ranking of the cases from least cost to most expensive. This ranking is only one factor used to determine the Preferred Plan. Other important factors that affect the selection of the Preferred Plan include: reliability, risk mitigation, resource diversity, consistency with Nevada's energy policies, carbon emissions and the needs of individual customers.

Scenario Analysis. The base fuel and purchased power price forecasts have been supplemented with additional fuel and purchased power price forecasts: high and low fuel and purchased power price forecasts. The mid-level carbon price assumption has been tested with three forecasts: high, low, and no carbon price sensitivities. Further details on these forecasts can be found in the Fuel and Purchased Power Price Forecast section.

The production costs, capital costs, and total PWRR results of all the scenarios can be found in Technical Appendices ECON-6 through ECON-7.

C. Updates to Key Modeling Assumptions

Area Configuration. The area configuration used in PROMOD has not changed from the one used in the 2021 Joint IRP. The purpose of the zonal model is to simulate transmission between areas. However, PROMOD is not a transmission flow model and the transmission flows determined by PROMOD are based on economics. PROMOD outputs do not represent actual flows. A graphical depiction of the area configuration used in this filing, along with the area location of each load and asset and the annual maximum transfer between areas, is provided in Technical Appendix ECON-8.

Hourly Load Forecast. The Companies' load forecast is unchanged from the forecast approved in Docket No. 21-06001, the Companies' 2021 Joint IRP.

Market Fundamentals. The Companies' market fundamentals forecasts have been updated from the forecasts used in the 2021 Joint IRP. Details on market fundamentals can be found in the Fuel and Purchased Power Price Forecasts section.

Existing Generation Operating Characteristics and Costs. The Companies continue to look for opportunities to improve the capacity, operating characteristics, and economics for existing generators. Most operating characteristics assumptions, including fixed operations and maintenance ("O&M"), of the Companies' generation fleet are shown in confidential Technical Appendix GEN-1. Upgrades to existing generators, including those approved in the 2021 Joint IRP and those proposed in this Amendment, are discussed in the Generation narrative.

Planning Reserves. In the 2021 Joint IRP, the Commission approved a 16 percent planning reserve margin ("PRM") for the Companies' capacity planning purposes. In this Amendment, the Companies continue to use the 16 percent PRM and decrease their available resources by 90 MW. As described in subsection B previously, the 90 MW is an approximation of reserves needed for

OATT customers, or unbundled customers, within the BAA. Each utility is assumed to carry a load ratio share of the total 90 MW needed for the BAA.

PPAs – including Renewables. Information for existing PPAs is modeled in accordance with the terms of the contract. The Companies continue to model renewable resources as must-take agreements and to use ELCC[48] to assign the capacity values associated with renewable resources at the time of the system peak.

Battery Modeling. The model of batteries has not changed from the methods used in the 2021 Joint IRP. The model of PV paired with BESS continues to be a single combined unit. This method preserves the facility interconnection limit and reasonably approximates the expected dispatch of the BESS. The expected dispatch may vary by contract but is fixed throughout the study period. The model of stand-alone BESS does not require that they be charged strictly from a solar resource. The charge/discharge cycle is based on economics.

Transmission Limits. Transmission limits, including access to external markets as well as limits between the Companies (over ON Line and/or Greenlink Nevada) were modeled in accordance with Technical Appendix ECON-8. Although PROMOD is not a transmission flow model, all transmission capacity constraints are included in the model. Any projected flows are based on economics and are not allowed to exceed the transmission capacities.

Negative Load. To capture an hourly output profile, the Companies modeled renewable resources as load-modifying transactions. That is, the projected hourly output from any renewable resource is subtracted from the expected hourly load. Unfortunately, subtracting the sum of all renewable resources from the forecast load can result in a negative number which will cause PROMOD to stop processing. To avoid this negative load, the Companies have modeled a zero-cost firm sale and an off-setting zero-cost generator in PROMOD. The zero-cost sale increases the load to ensure negative loads are not calculated. The zero-cost generator serves the zero-cost sale *unless* the sale is being served by the excess renewable energy. The difference between the sales energy and the generator energy is the excess renewable energy. This excess is labeled *dump energy* in the PROMOD output. Dump energy may also be referred to as solar overgeneration, curtailed energy, or excess energy.

Resource Buildout. As discussed earlier in this narrative, the Companies believe it is prudent to reduce its reliance on market capacity purchases – especially in the near term. To that end, the Companies are not planning significant changes to the 2021 Preferred Plan resource buildout approved in its 2021 Joint IRP. That is, the resource buildouts for each case analyzed in this Amendment use nearly the same firm dispatchable and renewable placeholders as were used in the 2021 Preferred Plan.

CER Inputs. The CER calculates the revenue requirements needed to recover capital costs of utility-owned resources, such as future generators or transmission infrastructure. Only native load allocations of transmission-related costs are included in the CER. The timing of the project cash flows during the construction period, AFUDC, and project book lives and tax lives are all factors

[48] *See* ELCC Report in Docket No. 20-07023, Technical Appendix ECON-5.

into the final annual revenue requirement that is included in the PWRR calculation. CER analysis can be found in Technical Appendices ECON-6 and ECON-7.

D. Assessment of Need

Figure EA-1 shows the 2021 Preferred Plan as approved in the 2021 Joint IRP. It shows the system capacity requirements (loads plus PRM), the resources currently defined by the Companies (owned resources and those under contract), and placeholder resources. The base load forecast was used, and the resource capacities shown are those that can be counted on at the time of the system peak. That is, thermal units are shown at their peak capacities and renewable units have been adjusted for their ELCC.

FIGURE EA-1
NV ENERGY CAPACITY POSITION
AS APPROVED IN 2021 JOINT IRP

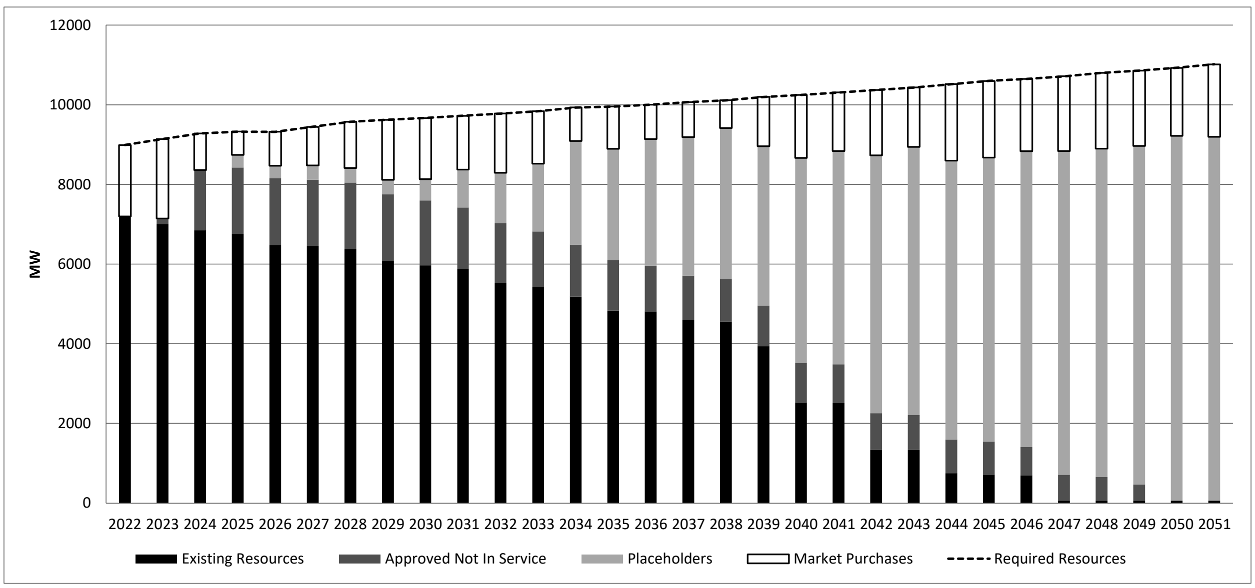


Figure EA-1 illustrates the expected steady increase in customer demand and the Companies' plan to meet the increased need with a combination of firm dispatchable resources, renewable resources and market purchases. This plan assumed that up to 2,000 MW of market capacity purchases would be available at a reasonable price during peak hours of the study period. That level of market capacity purchases was deemed an appropriate threshold based on past trading experience in Western power markets. Recent disruptions in typical peak market transactions, however, have caused the Companies to re-evaluate the acceptable level of market capacity purchases.

FIGURE EA-2
POTENTIAL UNCERTAINTY in
NV ENERGY'S CAPACITY POSITION

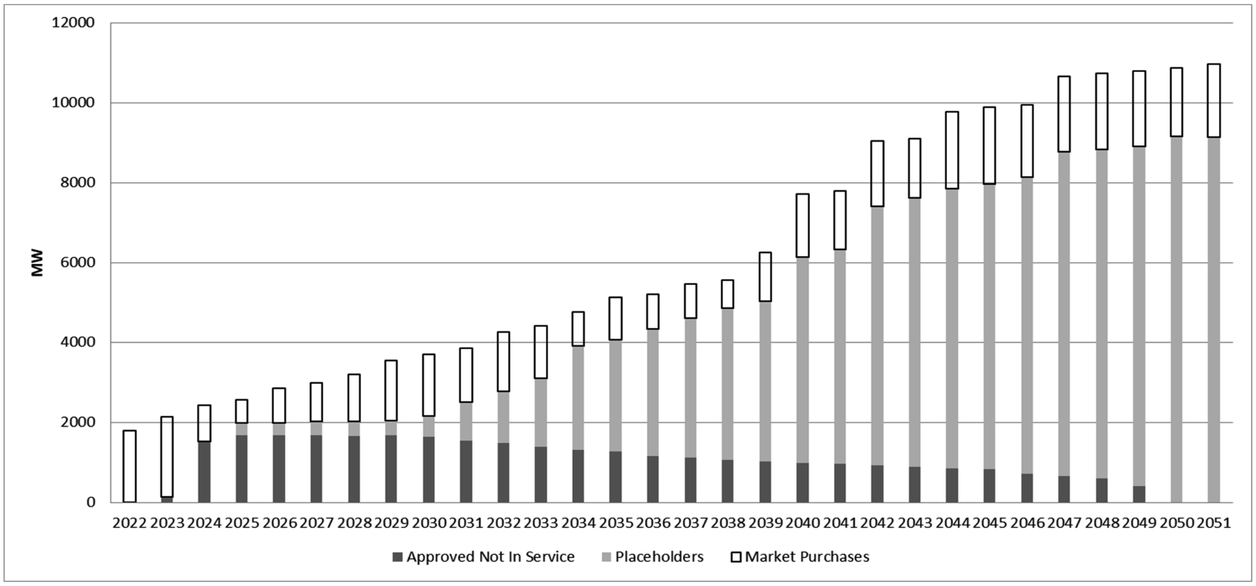


Figure EA-2 takes a closer look at the Companies' capacity position by removing the resources that are currently in operation. The figure shows the Companies have a significant reliance on market purchases for 2022-2023. The dependence drops for a few years beginning in 2024 then rebounds as early as 2029. While the decrease is encouraging, the reliance on the market is never eliminated. It is important to note the reduction in market purchases is also dependent on new resources meeting their projected commercial operation date. Additionally, by 2025, the Companies achieve the illustrated open position by adding placeholder capacity, as shown in the figure.

Recent disruptions in power market availability led the Companies to look for additional capacity within the BAA. The additional capacity will serve the immediate need to reduce the near-term open position as well as help the Companies to serve Nevada load with Nevada resources going forward.

E. Plan Development

NAC § 704.937(1) requires a supply plan to contain a "diverse set of alternative plans, which include a list of options for the supply of capacity and electric energy." Due to the Companies need to reduce its reliance on market purchases, these supply options need to be located within the BAA and be in commercial operation as soon as possible.

As previously described in the Renewables and Generation narratives, the Companies investigated many options for incremental resources for this Amendment. The resources that progressed to the economic analysis are shown below.

Capacity Upgrades to existing generating facilities.
As defined in the Generation narrative, the following capacity upgrades were examined in the analysis:

a) Wet compression at Sun Peak 3 through 5;
b) Peak firing at the Chuck Lenzie Combined Cycle Blocks 1 and 2, Harry Allen Combined Cycle, and Tracy Combined Cycle;
c) Chilled water storage at Chuck Lenzie Combined Cycle Blocks 1 and 2.

New combustion turbine generation.
A new 200 MW gas turbine with an in-service date of 2024 was analyzed. More information on this potential resource can be found in the Generation narrative.

New geothermal PPA.
The 25 MW North Valley geothermal plant was modeled as a potential resource for Sierra. More information on this PPA can be found in the Renewables narrative.

New stand-alone BESS.
Two-hour and 4-hour stand-alone BESS were each evaluated. Details of the size and operational characteristics of the BESS can be found in the Renewables narrative.

All cases were developed using the 2021 Preferred Plan, as approved by the Commission, as a starting point. No changes were made to the capacity or energy provided by proposed or placeholder renewable resources in that plan. Keeping the renewable generation constant with an unaltered load forecast ensured each plan met each company's RPS requirement and the state's 2050 clean energy goal.

The Companies grouped these candidates based on resource size (capacity) to create a series of screening analyses. The first screening analysis consisted of individual and combinations of generation fleet upgrades. Combinations of the best of the fleet upgrades and the new geothermal PPA were analyzed in the second screening. The Companies created a third screening analysis of the larger candidate resources – the combustion turbine and the 2-hour and the 4-hour BESS. The final screening analysis compared the present worth of individual and combinations of the best of the upgrades and geothermal PPA (second screen) and the best of the larger resources (third screen). The final alternative plans were selected from the last screening analysis.

L&R tables for each of the screening cases analyzed are provided in Technical Appendix ECON-5.

SCREENING ANALYSIS 1 - Upgrades to existing generation fleet. As described in the Key Modeling Assumptions section above, the Companies intentionally kept the long-term resource buildout for each case as presented in the 2021 Preferred Plan. The first 20 years of that buildout are shown in Figure EA-3.

FIGURE EA-3
NV ENERGY LONG-TERM RESOURCE BUILDOUT
AS PRESENTED IN 2021 JOINT IRP

	2021 IRP Preferred Plan	
	Sierra	Nevada Power
2023		
2024		
2025		350 MW PV - paired_25 276 MW BESS - paired_25
2026		
2027		229 MW PV - alone_27
2028		75 MW PV - alone_28
2034	168 MW Firm_NN_34	360 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34
2035		309 MW BESS - paired_35 309 MW PV - paired_35
2036	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36
2037		512 MW BESS - paired_37 512 MW PV - paired_37
2038		630 MW BESS - paired_38 630 MW PV - paired_38
2039	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39
2040	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40
2041	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41

The cases for the first screening analysis alter the above long-term resource buildout as described below. Details on each new project can be found in the Generation section of this Amendment.

Base Case: This case uses the long-term resource buildout described above. The case adds only the wet compression projects on the Clark Peakers and Harry Allen peaking units described in the Generation narrative to be complete before summer of 2022. It relies heavily on market purchases – especially in the first few years of the study period.

Sun Peak plan: This case adds approximately 21 MW of peak capacity to the Sun Peak Generating Station via wet compression. Each of the three combustion turbines at Sun Peak increase their peak rating by 7 MW. This upgrade is available by the summer 2023 and does not change the expected retirement date of the plant.

However, after the modeling was performed and all analysis completed, an opportunity arose to install the Sun Peak wet compression project prior to summer 2022. The economic analysis was conducted assuming a conservative installation date of summer 2023 due to potential permit modifications. Regardless, early installation does not increase the cost of the project but does reduce the open position in 2022.

Peak Firing plan: This case adds a total of about 48 MW of peak capacity to several of the existing combined-cycle generators. The affected generators are Chuck Lenzie Blocks 1 and 2, Harry Allen, and Tracy. Each of the plants/blocks will increase their peak rating by approximately 12 MW each. These upgrades will be available by the summer 2024 and do not change the expected retirement dates of any plant.

Cold Storage plan: This case adds approximately 18 MW of peak capacity to the Chuck Lenzie Generating Station by installing thermal energy storage. That is, each of the combined cycle blocks at Chuck Lenzie increase their peak rating by 9 MW. This upgrade is available by the summer 2024 and does not change the expected retirement date of either block.

Peak Firing and Cold Storage plan: This case adds a total of about 66 MW of peak capacity to the Companies' generating units through a combination of the Peak Firing and Cold Storage plans described above. The Chuck Lenzie units are capable of generating the additional capacity from both upgrades. These upgrades will be available by the summer 2024.

Peak Firing and Sun Peak plan: This case adds a total of about 69 MW of peak capacity to the Companies' generating units through a combination of the Peak Firing and Sun Peak plans described above.

Sun Peak and Cold Storage plan: This case adds a total of about 39 MW of peak capacity to the Companies' generating units through a combination of the Sun Peak and Cold Storage plans described above.

All Generator Upgrades plan: This case adds a total of about 87 MW of peak capacity to the Companies through a combination of the Sun Peak, Peak Firing, and Cold Storage plans described above.

The results of Screening Analysis 1 are shown in Figure EA-4 below. The PWRR for each of the scenarios is lower than the Base Case.

FIGURE EA-4
RESULTS OF SCREENING ANALYSIS 1
Total Costs

	20 Year PWRR 2022-2041 (million $)	30 Year PWRR 2022-2051 (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
Base Case	$ 20,191	$ 27,595	$ 8	$ 10
SunPeak	$ 20,191	$ 27,595	$ 8	$ 10
Peak Fire	$ 20,188	$ 27,590	$ 6	$ 6
Cold Storage	$ 20,185	$ 27,589	$ 3	$ 5
SunPeak_Peak Fire	$ 20,188	$ 27,589	$ 5	$ 5
SunPeak_Cold Storage	$ 20,185	$ 27,589	$ 2	$ 4
Peak Fire_Cold Storage	$ 20,182	$ 27,585	$ -	$ -
all gen upgrades	$ 20,182	$ 27,585	$ 0	$ 0

The All Generator Upgrades plan was chosen as the best of the first screening analysis. It has nearly the same cost as the Peak Fire and Cold Storage case, with the added benefit of 21 MW of additional capacity in the BAA, providing the lowest exposure to the uncertain availability of market capacity.

SCREENING ANALYSIS 2 – Generator Upgrades and new PPA. The purpose of the second screening analysis is to compare the benefits of a new geothermal PPA with that of the All Generator Upgrades plan.

The cases for the second screening analysis use the same long-term resource buildout shown in Figure EA-3. Any changes to that buildout are described below:

Base Case: This case is the same as the base case in screening analysis 1 and all other screening analyses.

North Valley Geothermal plan: This case adds 25 MW of geothermal capacity to Sierra. Due to the impact of ELCC, this option reduces the open position by about 11 MW. The commercial operation date for this PPA is December 2022 and the term of the contract is 25 years. More information on the project is described in the Renewables narrative.

All Generator Upgrades plan: The best of screening analysis 1, which adds 87 MW of capacity to the Companies' generating units as described above.

All Generator Upgrades + North Valley plan: This case is a combination of the North Valley and All Generator Upgrades plans described above. Approximately 98 MW of capacity is added to the Companies' system.

The results of screening analysis 2 are shown in Figure EA-5 below.

FIGURE EA-5
RESULTS OF SCREENING ANALYSIS 2
Total Costs

	20 Year PWRR 2022-2041 (million $)	30 Year PWRR 2022-2051 (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
Base Case	$ 20,191	$ 27,595	$ 8	$ 10
North Valley	$ 20,248	$ 27,655	$ 65	$ 70
all gen upgrades	$ 20,182	$ 27,585	$ -	$ -
all gen upgrades + North Valley	$ 20,239	$ 27,644	$ 56	$ 59

The All Generator Upgrades + North Valley plan was chosen as the best of the second screening analysis. Although not the low-cost plan, it adds diversity in the type of renewables in the system and provides the lowest exposure to the uncertain availability of market capacity, as well as additional near-term capacity to Sierra.

SCREENING ANALYSIS 3 – Large Capacity Additions. The purpose of the third screening analysis is to compare the benefits of adding large amounts of new capacity without regard of other potential resources. Specifically, resources from screening analyses 1 and 2 were ignored in this analysis. Because of the relatively large size of these candidate resources, some adjustments were made to the long-term resource buildout for each case. The shaded information in Figure EA-6 highlights the changes in each case.

FIGURE EA-6
RESOURCE BUILDOUTS FOR SCREENING ANALYSIS 3

	2-hr BESS		4-hr BESS		CT	
	Sierra	Nevada Power	Sierra	Nevada Power	Sierra	Nevada Power
2023		2-hr BESS		4-hr BESS		
2024						Silverhawk CT
2025		350 MW PV - paired_25 276 MW BESS - paired_25		350 MW PV - paired_25 276 MW BESS - paired_25		350 MW PV - paired_25 276 MW BESS - paired_25
2026						
2027		229 MW PV - alone_27		229 MW PV - alone_27		229 MW PV - alone_27
2028		75 MW PV - alone_28		75 MW PV - alone_28		75 MW PV - alone_28
2034	168 MW Firm_NN_34	180 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34	168 MW Firm_NN_34	270 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34	168 MW Firm_NN_34	180 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34
2035		309 MW BESS - paired_35 309 MW PV - paired_35		309 MW BESS - paired_35 309 MW PV - paired_35		309 MW BESS - paired_35 309 MW PV - paired_35
2036	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36
2037		512 MW BESS - paired_37 512 MW PV - paired_37		512 MW BESS - paired_37 512 MW PV - paired_37		512 MW BESS - paired_37 512 MW PV - paired_37
2038		630 MW BESS - paired_38 630 MW PV - paired_38		630 MW BESS - paired_38 630 MW PV - paired_38		630 MW BESS - paired_38 630 MW PV - paired_38
2039	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39
2040	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40
2041	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41

Base Case: This case is the same as the base case in all other screening analyses. Note that this case, used in all screening analyses, includes 360 MW of firm dispatchable placeholder resources added in 2034.

2-hour BESS: This case adds a 220 MW/440 MWh grid-tied battery to Nevada Power. Half (180 MW) of the firm dispatchable resource placeholder added in 2034 in the base case was removed from this case due to the addition of the 2-hour BESS, as shown in Figure EA-6. The commercial operation date for this BESS is expected in May 2023. The BESS has an expected book life of 20 years. More information on this resource is provided in the Renewables narrative.

4-hour BESS: This case adds a 110 MW/440 MWh grid-tied battery to Nevada Power. In this case, only 90 MW of the firm dispatchable resource added in 2034 in the base case was removed due to the addition of the 4-hour BESS. For modeling purposes, the commercial operation date for this BESS is expected in May 2023. The BESS has an expected book life of 20 years. Details of this resource are provided in the Renewables narrative.

200 MW CT: This case adds approximately 200 MW from a combustion turbine generator to Nevada Power. Half (180 MW) of the firm dispatchable resource placeholder added in 2034 in the base case was removed from this case due to the addition of the 200 MW CT. For modeling purposes, the commercial operation date for the generator is in May 2024, and the generator has an expected book life of 30 years. Details of this resource are provided in the Generation narrative.

A case combining the 2-hour and 4-hour batteries was not created because the BESS supplier could not deliver both units by 2025.

The results of Screening Analysis 3 are shown in Figure EA-7 below.

FIGURE EA-7
RESULTS OF SCREENING ANALYSIS 3

Total Costs

	20 Year PWRR 2022-2041 (million $)	30 Year PWRR 2022-2051 (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
Base Case	$ 20,191	$ 27,595	$ -	$ -
2-hr BESS	$ 20,283	$ 27,694	$ 92	$ 99
4-hr BESS	$ 20,323	$ 27,732	$ 133	$ 137
Silverhawk CT	$ 20,348	$ 27,752	$ 157	$ 157

The case with the 2-hour BESS was chosen as the best of screening analysis 3. Although higher cost than the base case, it reduces the Companies' reliance on market capacity at the lowest cost and without adding new fossil generation to the system.

SCREENING ANALYSIS 4 – Combinations. The purpose of the fourth screening analysis is to compare the benefits of adding smaller amounts of new capacity (best of screening analysis 2) with the benefits of adding larger amounts of new capacity (best of screening analysis 3) and combinations thereof. Similar to screening analysis 3, some adjustments were made in the placeholder resource additions in 2034 to maintain consistency in the cases.

Descriptions of screening analysis 4 are presented below.

Base Case: This case is the same as the base case in all other screening analyses. Again, note that this case, used in all screening analyses, includes 360 MW of firm dispatchable placeholder resources added in 2034.

All Generator Upgrades + North Valley plan: The best of screening analysis 2, which adds approximately 98 MW of capacity to NV Energy and a 360 MW firm dispatchable placeholder added in 2034.

2-hour BESS: The best of screening analysis 3, which adds a 220 MW/440 MWh grid-tied battery to Nevada Power. The firm dispatchable placeholder added in 2034 is reduced to 180 MW.

All Gen Upgrades + NValley + 2-hr BESS: This case combines the best of screening analyses 2 and 3. The firm dispatchable placeholder added in 2034 is reduced to 180 MW.

All Gen Upgrades + NValley + CT: This case combines all the generator upgrades, the North Valley PPA and a 200 MW combustion turbine. The firm dispatchable placeholder added in 2034 is reduced to 180 MW.

All Gen Upgrades + NValley + 2-hr BESS + CT: This case maximizes all the capacity added to the Companies' system discussed above besides the 4-hr BESS. In 2024, approximately 500 MW of capacity is added to the system. This case eliminates the need for the firm dispatchable placeholder added in 2034.

The results of the Screening Analysis 4 are shown in Figure EA-8 below.

FIGURE EA-8
RESULTS OF SCREENING ANALYSIS 4
Total Costs

	20 Year PWRR 2022-2041 (million $)	30 Year PWRR 2022-2051 (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
Base Case	$ 20,191	$ 27,595	$ -	$ -
all + North Valley	$ 20,239	$ 27,644	$ 48	$ 49
2-hr BESS	$ 20,280	$ 27,691	$ 89	$ 96
all + North Valley + 2-hr BESS	$ 20,333	$ 27,745	$ 142	$ 151
all + N Valley + CT	$ 20,395	$ 27,800	$ 204	$ 206
all + N Valley + 2-hr BESS + CT	$ 20,480	$ 27,886	$ 289	$ 292

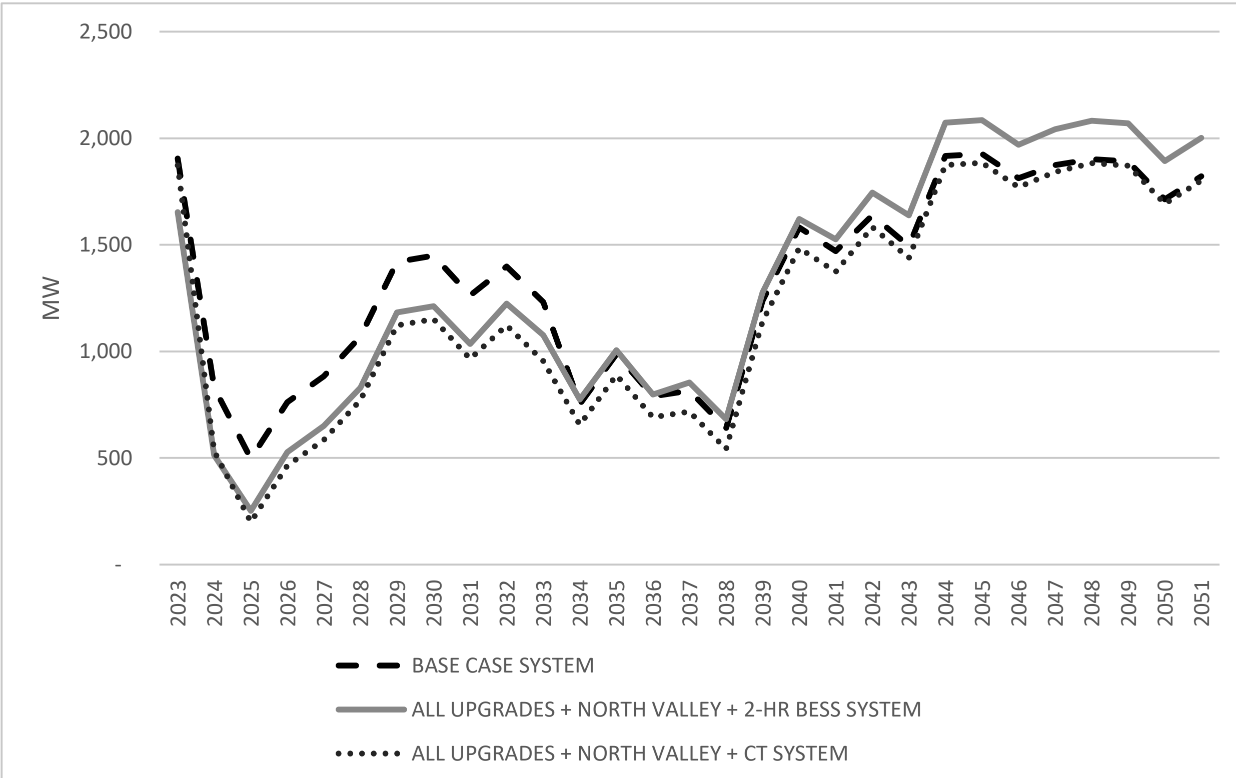
ALTERNATIVE CASES. From the exhaustive series of screening analyses, the Companies selected the All Generator Upgrades + North Valley PPA + 2-hr BESS and the All Generator Upgrades + North Valley PPA + CT as the two alternative cases for the Amendment. The full resource buildouts for these cases are shown in Figure EA-9, with changes relative to the Base Case highlighted. The Base Case is included in Figure EA-9 for reference.

FIGURE EA-9
RESOURCE BUILDOUT FOR BASE AND ALTERNATIVE CASES

	BASE CASE		2-hr BESS		CT	
	Sierra	Nevada Power	Sierra	Nevada Power	Sierra	Nevada Power
2023			North Valley Geo	Sun Peak wet compression 2-hr BESS	North Valley Geo	Sun Peak wet compression
2024			Tracy Peak fire	Lenzie & HA peak fire Lenzie cold storage	Tracy Peak fire	Lenzie & HA peak fire Lenzie cold storage Silverhawk CT
2025		350 MW PV - paired_25 276 MW BESS - paired_25		350 MW PV - paired_25 276 MW BESS - paired_25		350 MW PV - paired_25 276 MW BESS - paired_25
2026						
2027		229 MW PV - alone_27		229 MW PV - alone_27		229 MW PV - alone_27
2028		75 MW PV - alone_28		75 MW PV - alone_28		75 MW PV - alone_28
2034	168 MW Firm_NN_34	360 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34	168 MW Firm_NN_34	180 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34	168 MW Firm_NN_34	180 MW Firm_SN_34 561 MW BESS - paired_34 561 MW PV - paired_34
2035		309 MW BESS - paired_35 309 MW PV - paired_35		309 MW BESS - paired_35 309 MW PV - paired_35		309 MW BESS - paired_35 309 MW PV - paired_35
2036	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36	304 MW BESS - paired_36 304 MW PV - paired_36	305 MW BESS - paired_36 305 MW PV - paired_36
2037		512 MW BESS - paired_37 512 MW PV - paired_37		512 MW BESS - paired_37 512 MW PV - paired_37		512 MW BESS - paired_37 512 MW PV - paired_37
2038		630 MW BESS - paired_38 630 MW PV - paired_38		630 MW BESS - paired_38 630 MW PV - paired_38		630 MW BESS - paired_38 630 MW PV - paired_38
2039	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39	86 MW BESS - alone_39	361 MW BESS - paired_39 361 MW PV - paired_39
2040	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40	100 MW BESS - alone_40	476 MW BESS - paired_40 476 MW PV - paired_40 900 MW Firm_SN_40
2041	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41	69 MW BESS - alone_41	394 MW BESS - paired_41 394 MW PV - paired_41
2042	313 MW BESS - alone_42	349 MW BESS - paired_42 349 MW PV - paired_42 900 MW Firm_SN_42	313 MW BESS - alone_42	349 MW BESS - paired_42 349 MW PV - paired_42 900 MW Firm_SN_42	313 MW BESS - alone_42	349 MW BESS - paired_42 349 MW PV - paired_42 900 MW Firm_SN_42
2043	453 MW BESS - alone_43	423 MW BESS - paired_43 423 MW PV - paired_43	453 MW BESS - alone_43	423 MW BESS - paired_43 423 MW PV - paired_43	453 MW BESS - alone_43	423 MW BESS - paired_43 423 MW PV - paired_43
2044		736 MW BESS - paired_44 736 MW PV - paired_44		736 MW BESS - paired_44 736 MW PV - paired_44		736 MW BESS - paired_44 736 MW PV - paired_44
2045	450 MW BESS - paired_45 450 MW PV - paired_45		450 MW BESS - paired_45 450 MW PV - paired_45		450 MW BESS - paired_45 450 MW PV - paired_45	
2046	25 MW BESS - paired_46 25 MW PV - paired_46	751 MW BESS - paired_46 751 MW PV - paired_46	25 MW BESS - paired_46 25 MW PV - paired_46	751 MW BESS - paired_46 751 MW PV - paired_46	25 MW BESS - paired_46 25 MW PV - paired_46	751 MW BESS - paired_46 751 MW PV - paired_46
2047	1705 MW BESS - paired_47 1705 MW PV - paired_47	585 MW BESS - paired_47 670 MW PV - paired_47	1705 MW BESS - paired_47 1705 MW PV - paired_47	585 MW BESS - paired_47 670 MW PV - paired_47	1705 MW BESS - paired_47 1705 MW PV - paired_47	585 MW BESS - paired_47 670 MW PV - paired_47
2048	124 MW BESS - paired_48 124 MW PV - paired_48	185 MW BESS - paired_48 185 MW PV - paired_48	124 MW BESS - paired_48 124 MW PV - paired_48	185 MW BESS - paired_48 185 MW PV - paired_48	124 MW BESS - paired_48 124 MW PV - paired_48	185 MW BESS - paired_48 185 MW PV - paired_48
2049	593 MW BESS - paired_49 593 MW PV - paired_49	70 MW BESS - paired_49 70 MW PV - paired_49	593 MW BESS - paired_49 593 MW PV - paired_49	70 MW BESS - paired_49 70 MW PV - paired_49	593 MW BESS - paired_49 593 MW PV - paired_49	70 MW BESS - paired_49 70 MW PV - paired_49
2050		2323 MW BESS - paired_50 2323 MW PV - paired_50		2323 MW BESS - paired_50 2323 MW PV - paired_50		2323 MW BESS - paired_50 2323 MW PV - paired_50

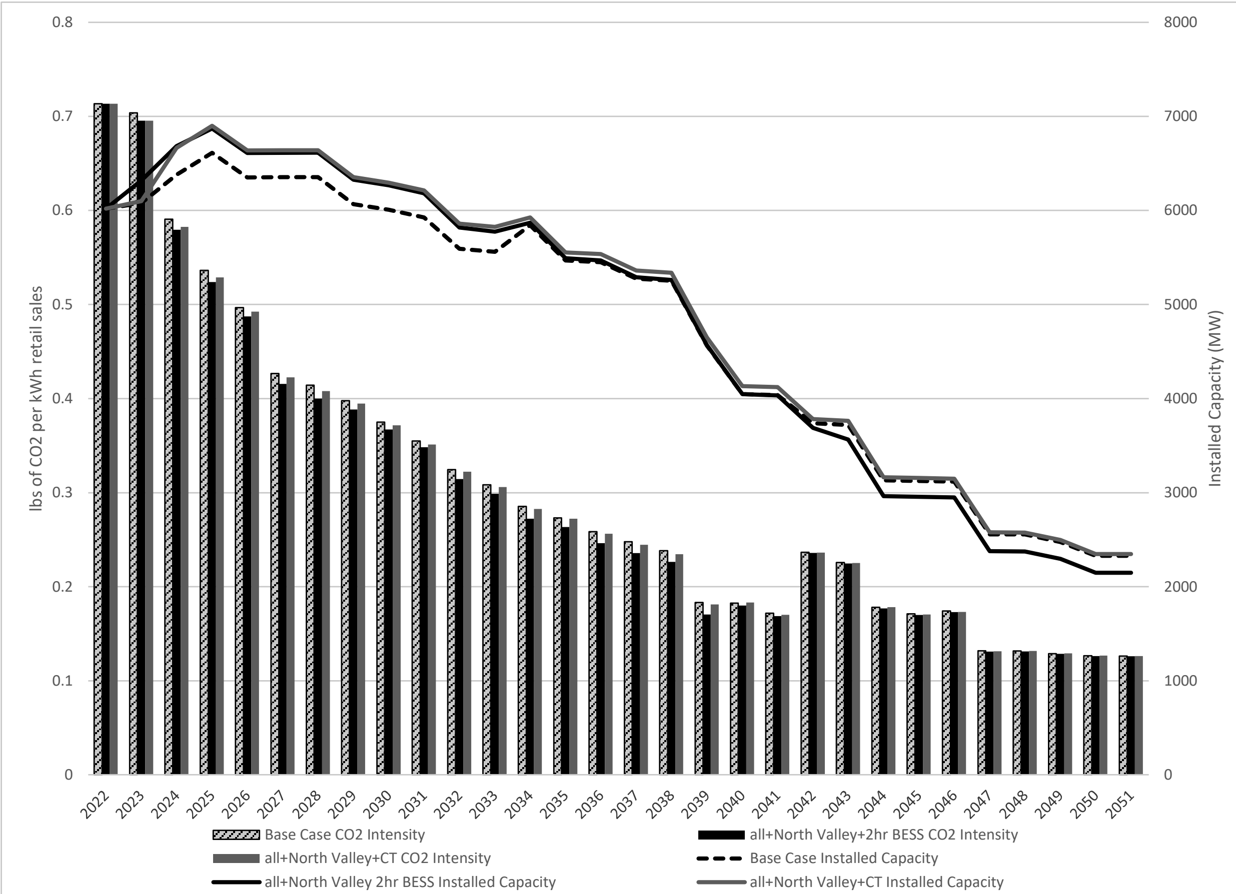
Open Positions and Open Position Capacity Costs. Figure EA-10 shows the open positions of each plan assuming the base load forecast. The Base Case is shown for reference only.

FIGURE EA-10
OPEN POSITIONS FOR EACH PLAN
(BASE LOAD)



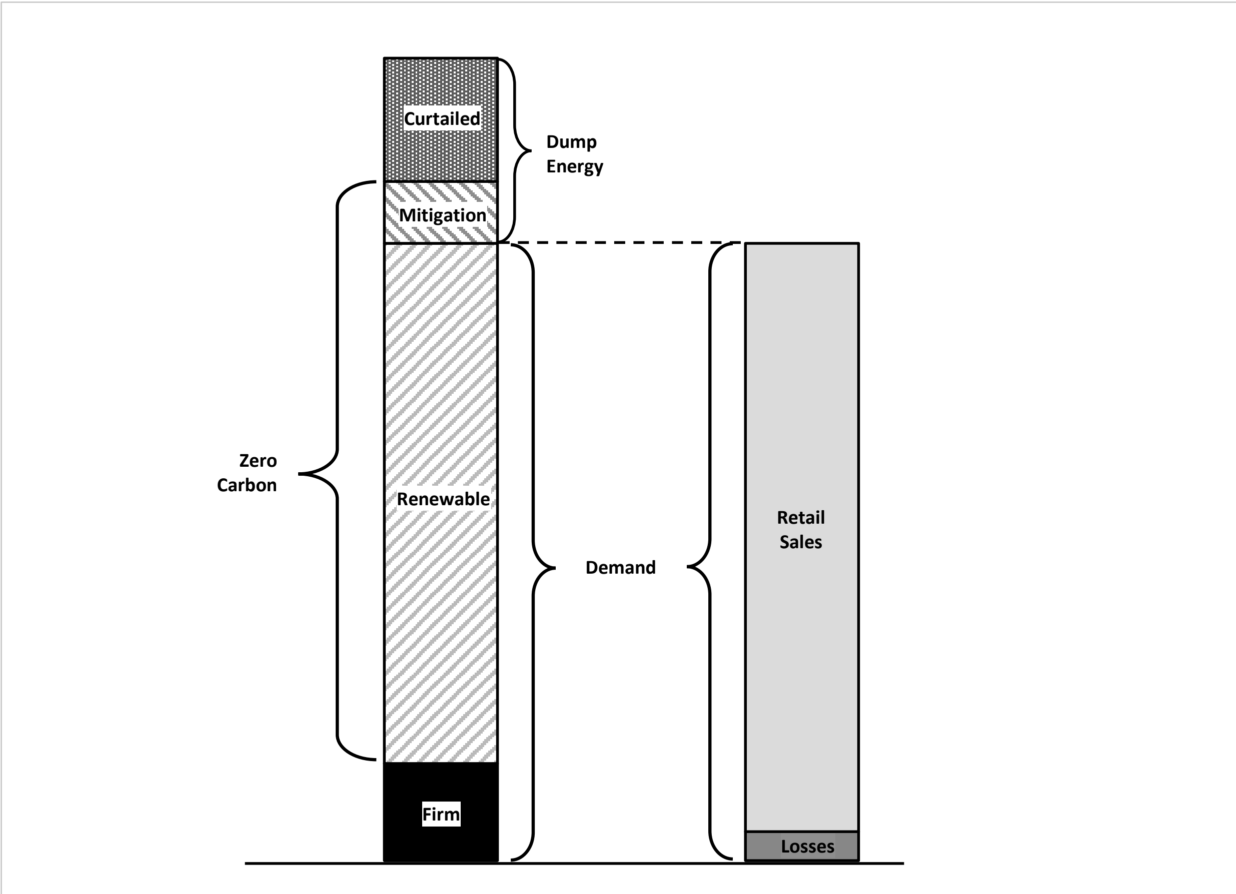
Carbon Emissions. Each plan started with the 2021 Preferred Plan, which meets the state's 2050 clean energy goal. In that way, each plan proposed in this Amendment also meets this state goal. A comparison of the carbon intensity of the alternative plans in pounds ("lbs") of carbon per kWh of retail sales is depicted in Figure EA-11 below. The base case is shown for reference only.

FIGURE EA-11
JOINT SYSTEM CARBON INTENSITY



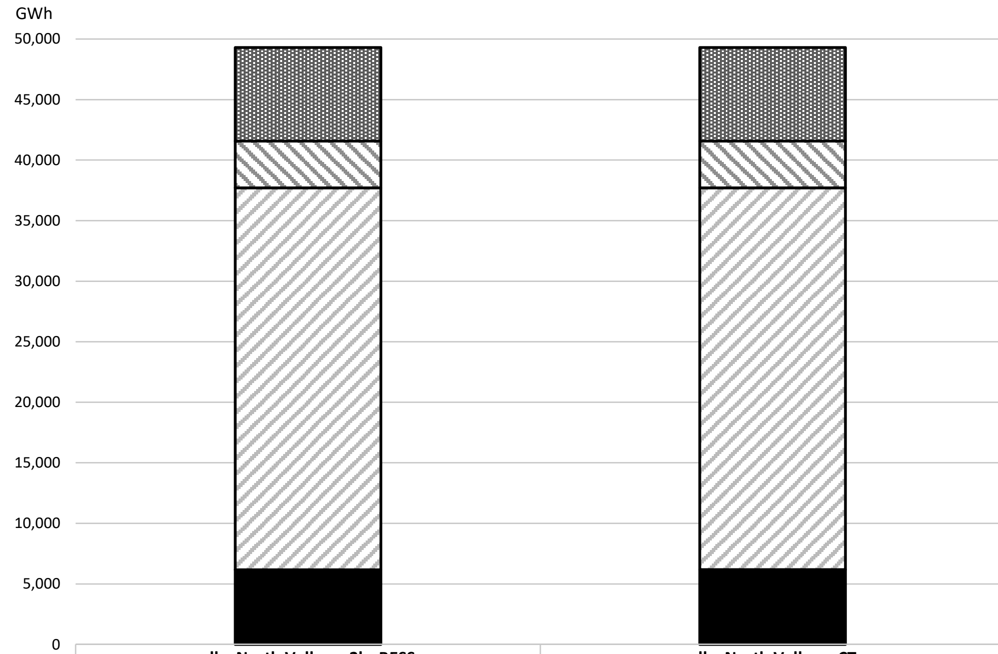
Calculation of Zero-Carbon Generation. The state's 2050 clean energy goal requires an amount of generation from zero-carbon dioxide emission resources that is equal to electricity sales in 2050. This analysis in the Amendment is performed in the same manner as in the 2021 Joint IRP - considering only generation owned or under contract to the Companies. Figure EA-12 was prepared to help explain how the Companies calculated the zero carbon generation. The PROMOD analysis determines the generation to serve customer demand. Demand is the sum of retail sales plus system losses. Generation consists of energy produced by renewable and non-renewable resources and a portion of the overgeneration (or dump) energy. As indicated in the discussion of the cases in the 2021 Joint IRP, the Companies believe a portion of overgeneration will be mitigated. That is, a portion of overgenerated energy may be used by the system through better utilization of the batteries or through off-system sales. For the purposes of calculating zero-carbon generation, the Companies have assumed approximately one-third of the overgeneration would be mitigated. The remaining excess energy would be curtailed.

FIGURE EA-12
ILLUSTRATION OF ANNUAL ENERGY PRODUCTION
FOR CALCULATION OF ZERO-CARBON GENERATION



Using the explanation above, the Companies calculated the zero-carbon generation for each case in 2050. The results of the calculation, shown both in MWh and as a percentage of retail load, is presented in Figure EA-13. A breakdown of the energy mix for these cases is provided in Technical Appendix ECON-4.

FIGURE EA-13
CALCULATION OF 2050 GENERATION BY CASE



	all + North Valley + 2hr BESS	all + North Valley + CT
Curtailed	7,713	7,717
Mitigation	3,856	3,859
Renewables	31,553	31,546
Firm Dispatchable	6,168	6,174

Zero Carbon Generation (Renewables+Mitigation)	35,409	35,405
Retail Sales	35,945	35,945
Percent Zero Carbon Generation	99%	98%

F. Economic Analysis Results

The results of the base load, base fuel, and mid-carbon price analysis for the alternative cases is shown below in Figure EA-14.

FIGURE EA-14
ALTERNATIVE CASES

Total Costs

	20 Year PWRR 2022-2041 (million $)	30 Year PWRR 2022-2051 (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
all + North Valley + 2-hr BESS	$ 20,333	$ 27,745	$ -	$ -
all + N Valley + CT	$ 20,395	$ 27,800	$ 62	$ 55

The results of sensitivity analyses are presented in Figures EA-15 and EA-16, which present the PWRR for fuel and purchase power price and carbon sensitivities over 20 and 30 years, respectively. A discussion of key findings follows the figures.

FIGURE EA-15
20-YEAR PWRR FOR ALL PLANS AND SENSITIVITIES

20-year PWRR ($ millions) by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	$ 20,333	$ 19,500	$ 20,788	$ 19,884	$ 25,444	$ 17,675
all + N Valley + CT	$ 20,395	$ 19,551	$ 20,858	$ 19,944	$ 25,541	$ 17,719

20-year PWRR Differential ($ millions) by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	$ -	$ -	$ -	$ -	$ -	$ -
all + N Valley + CT	$ 62	$ 52	$ 70	$ 59	$ 97	$ 45

20-year PWRR Ranking by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	1	1	1	1	1	1
all + N Valley + CT	2	2	2	2	2	2

FIGURE EA-16
30-YEAR PWRR FOR ALL PLANS AND SENSITIVITIES

30-year PWRR ($ millions) by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	$ 27,745	$ 26,202	$ 28,508	$ 27,010	$ 34,957	$ 24,350
all + N Valley + CT	$ 27,800	$ 26,246	$ 28,570	$ 27,062	$ 35,072	$ 24,387

30-year PWRR Differential ($ millions) by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	$ -	$ -	$ -	$ -	$ -	$ -
all + N Valley + CT	$ 55	$ 44	$ 63	$ 52	$ 115	$ 37

30-year PWRR Ranking by Scenario						
	Base Load					
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC
all + North Valley + 2-hr BESS	1	1	1	1	1	1
all + N Valley + CT	2	2	2	2	2	2

The key findings of the 20-year and 30-year PWRR analysis are summarized below.

- The All Generator Upgrades+North Valley+2-hr BESS has the lowest the 20-year and 30-year PWRR for all fuel, market and carbon price scenarios.
- The All Generator Upgrades+North Valley+2-hr BESS case has less excess energy than the All Generator Upgrades+North Valley+CT case.

The production costs, capital costs, and total PWRR results for all the scenarios are found in Technical Appendix items ECON-6 and ECON-7.

G. Loads and Resources Tables

NAC § 704.945 requires a table of loads and resources for each alternative plan analyzed. For the Preferred Plan, the 20-year projection of peak load, planning reserve requirements, total required resources, existing and future supply-side resources, existing and future demand-side resources, and reserves for OATT customers are provided in Figure EA-17. L&R tables for each company under the alternative plans and for each scenario are provided in Technical Appendix ECON-5.

Overview. The L&R tables provide the forecasted peak load (in MW) for the peak hour of the peak day of the year ("Peak Load"), plus a planning reserve requirement (together with Peak Load, "Required Resources"), and the forecasted capacities of the existing and future supply-side and demand-side resources (in MW) available to meet the Required Resources reduced by the OATT reserve.

The Peak Load includes wholesale firm sales and is net of demand-side resources including demand-side management programs, demand response programs, and net metering programs. Loads within the BAA for customers that supply their own supply-side, such as those authorized to procure their own energy supply under NRS Chapter 704B, are not included in the load that the Companies plan to serve.

A 16 percent PRM is added to the Peak Load to determine the Required Resources. This PRM was approved by the Commission in the 2021 Joint IRP to achieve a loss of load probability of no more than one day in 10 years. In addition, the PRM helps ensure that the Companies plan for sufficient supply-side resources and demand-side resources to meet the total requirements of bundled customers.

Supply-side resources include a combination of existing, proposed, and placeholder generation and PPAs, both conventional and renewable. The capacity value assigned to supply-side resources represents the effective capacity of each resource during the Peak Load.

Per the Phase 2 Stipulation in the 2021 Joint IRP, a reduction of 90 MW is taken from the total available resources to account for the reserves to be held for OATT customers. The 90 MW of reserves are split between the Companies based on ratio of load in each region.

Overall, the L&R tables represent the diverse set of resource options maintained by the Companies to meet the expected Required Resources.

Methodology for Assigning L&R Capacity Values for Existing and Future Resources.

The capacity at the time of Peak Load for existing conventional generation is listed in Technical Appendix GEN-1. The capacity for thermal generators varies depending on the time of year and is categorized as winter capacity, summer capacity or peak capacity. The peak capacity value is used for existing conventional generators in the L&R tables. For conventional generation PPAs, the contractually agreed upon capacity during the Peak Load hour is used.

The capacity value for renewable resources reflected on the L&R table is adjusted by the ELCC for the particular resource type with consideration of the overall renewable penetration. The L&R capacity value for all (existing and new) solar PV, battery and PV/BESS resources vary inversely with the amount of intermittent renewable penetration on the system. That is, as the total aggregate amount of nameplate intermittent renewable capacity increases, the ELCC as a percent of nameplate capacity decreases. The L&R capacity value for geothermal resources, by constrast, does not vary significantly with the amount of resource on the system.

The Companies introduced a new resource in this analysis, the 2-hour BESS. The ELCC for the 2-hour BESS was assumed to be the same as for a 4-hour BESS. The Companies believe this is a reasonable assumption for a single installation. If additional 2-hour BESS were considered, however, a detailed analysis of the appropriate ELCC would be needed, as it would be expected to decline much faster than the ELCC of 4-hour BESS with increased penetration.

The L&R tables show existing contracts expiring per the contract expiration date. Renewable placeholder contracts are added as needed to meet load growth, requirements for RPS compliance and, in some cases, for achievement of the state's 2050 clean energy goal.

Since the L&R tables provide a projection of capacity only, the capacity values cannot be extrapolated to forecast retail energy sales, total megawatt-hour output from conventional and renewable resources, or portfolio credit contributions to meet Nevada's RPS.

<u>Combined L&R Table.</u> Figure EA-17 provides the L&R table for the Preferred Plan under the Base Load scenario.

FIGURE EA-17
L&R TABLE
PREFERRED PLAN
(2022-2041)

1	**NV Energy**																				
2	**LOADS AND RESOURCES TABLE**																				
3	*all + North Valley + 2hr BESS*																				
4		**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
5	Gross Peak	8,075	8,284	8,496	8,619	8,693	8,879	9,029	9,184	9,286	9,403	9,504	9,570	9,686	9,791	9,864	9,945	10,006	10,057	10,182	10,249
6	DSM	76	117	150	183	216	242	282	318	352	386	406	412	450	454	456	458	444	422	462	462
7	Private Generation	86	116	166	203	239	274	275	334	360	384	411	418	413	482	507	531	558	559	604	629
8	Avoided Capacity	163	173	180	193	202	218	220	235	239	251	255	257	261	271	277	277	284	285	281	267
9	Forecast System Peak	7,750	7,878	8,000	8,040	8,036	8,145	8,252	8,298	8,335	8,382	8,432	8,483	8,562	8,584	8,624	8,679	8,719	8,791	8,835	8,890
10	Sales Obligations																				
11	**NET System Peak**	7,750	7,878	8,000	8,040	8,036	8,145	8,252	8,298	8,335	8,382	8,432	8,483	8,562	8,584	8,624	8,679	8,719	8,791	8,835	8,890
12	Planning Reserves (16%)	1,240	1,261	1,280	1,286	1,286	1,303	1,320	1,328	1,334	1,341	1,349	1,357	1,370	1,373	1,380	1,389	1,395	1,407	1,414	1,422
13	**REQUIRED RESOURCES**	8,990	9,139	9,280	9,326	9,322	9,448	9,572	9,626	9,669	9,723	9,781	9,840	9,932	9,957	10,004	10,068	10,114	10,198	10,249	10,312
14	OATT Reserves	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
15	**AVAILABLE RESOURCES**	7,271	7,486	8,768	9,073	8,795	8,797	8,741	8,443	8,456	8,688	8,556	8,764	9,157	8,950	9,206	9,213	9,432	8,920	8,628	8,787
16	OPEN Position	1,719	1,653	512	253	527	651	831	1,183	1,213	1,035	1,225	1,076	775	1,007	798	855	682	1,278	1,621	1,525
17																					
18																					
19	Company	(All)																			
20																					
21	Sum of Value	Column Labels																			
22	Row Labels	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
23	existing																				
24	NVE.existing.Coal	261	261	261	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	NVE.existing.Gas	5,748	5,807	5,807	5,807	5,807	5,807	5,807	5,519	5,471	5,417	5,103	5,103	4,888	4,527	4,527	4,369	4,369	3,691	2,288	2,288
26	NVE.existing.Renewable.BESS	10	10	310	522	522	523	525	526	516	494	473	441	413	402	384	369	349	337	324	315
27	NVE.existing.Renewable.PV	11	10	93	139	141	136	134	134	128	123	119	112	106	103	100	95	95	93	92	89
28	NVE.existing.Renewable.WH	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
29	PPA.existing.Conventional	346	173	171	170	167	165	163	163	164	164	152	152	152	152	152	152	152	152	152	152
30	PPA.existing.Renewable.BESS	100	176	903	798	798	801	802	803	789	733	702	654	616	600	536	467	440	425	409	397
31	PPA.existing.Renewable.CSP	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	PPA.existing.Renewable.GEO	174	162	162	162	154	143	132	121	70	70	60	5	5	5	5	5	-	-	-	-
33	PPA.existing.Renewable.HYDRO	9	9	9	6	6	6	2	-	-	-	-	-	-	-	-	-	-	-	-	-
34	PPA.existing.Renewable.LFG	9	9	9	9	9	9	9	9	9	9	9	-	-	-	-	-	-	-	-	-
35	PPA.existing.Renewable.PV	618	632	740	615	608	585	581	581	561	532	514	485	455	442	410	381	343	336	326	325
36	PPA.existing.Renewable.WIND	20	20	20	20	20	20	20	20	20	20	20	-	-	-	-	-	-	-	-	-
37	existing Total	7,361	7,324	8,540	8,564	8,287	8,250	8,180	7,881	7,733	7,567	7,157	6,957	6,640	6,236	6,119	5,843	5,753	5,039	3,596	3,566
38	placeholder																				
39	NVE.placeholder.future	-	-	-	-	-	-	-	-	-	-	-	-	348	348	348	348	348	348	1,248	1,248
40	NVE.placeholder.renewable.BESS	-	-	-	244	244	245	245	246	367	713	948	1,256	1,571	1,742	2,063	2,299	2,545	2,716	2,926	3,086
41	NVE.placeholder.renewable.PV	-	-	-	62	62	99	112	112	156	216	259	315	372	402	460	513	584	619	665	698
42	PPA.placeholder.renewable.WIND	-	-	-	-	-	-	-	-	-	-	29	85	85	85	85	85	85	85	85	85
43	placeholder Total	-	-	-	306	306	344	357	358	523	929	1,236	1,656	2,376	2,577	2,956	3,245	3,562	3,768	4,924	5,117
44	Proposed																				
45	NVE.Proposed.Gas																				
46	1-Sun Peak wet compress_23	-	21	21	21	21	21	21	21	21	21	-	-	-	-	-	-	-	-	-	-
47	1-Lenzie 1 Peak Firing_24	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
48	1-Lenzie 2 Peak Firing_24	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
49	1-HA Peak Firing_24	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
50	1-Tracy Peak Firing_24	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
51	1-Lenzie 1 Cold Storage_24	-	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
52	1-Lenzie 2 Cold Storage_24	-	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
53	NVE.Proposed.Gas Total	-	21	87	87	87	87	87	87	87	87	66	66	66	66	66	66	66	66	66	66
54	NVE.Proposed.renewable.BESS																				
55	220 MW RG BESS - 2 hr_23	-	220	220	195	194	195	196	196	192	184	176	164	154	150	144	138	130	126	121	117
56	NVE.Proposed.renewable.BESS Total	-	220	220	195	194	195	196	196	192	184	176	164	154	150	144	138	130	126	121	117
57	NVE.Proposed.renewable.GEO																				
58	25 MW North Valley GEO_23	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
59	NVE.Proposed.renewable.GEO Total	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
60	Proposed Total	-	252	318	293	292	293	294	294	290	282	253	241	231	227	221	215	207	203	198	194

H. Environmental Externalities and Net Economic Benefits

Nevada regulations require NV Energy to consider environmental costs and "net economic benefits" (which are generally termed "economic impacts") when analyzing alternative resource cases.

1. Overview of Relevant Regulations

The regulations require the Companies to rank power supply options on the basis of the PWRR and the Present Worth of Societal Costs ("PWSC"). The PWSC of a resource case is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility…."[49] Environmental costs are defined by the Commission as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan."[50] In addition, the August 2018 Order of the Commission in Docket No. 17-07020 ("August 2018 Order") requires that environmental costs include estimates of the "social cost of carbon" and prescribes a methodology for their calculation. The regulations state that "environmental costs to the State associated with operating and maintaining a supply plan or demand-side plan must be quantified for air emissions, water and land use and the social cost of carbon as calculated pursuant to subsection 5 of NAC § 704.937."[51]

The regulations also require the Companies to assess the "net economic benefits" of cases under certain circumstances, as noted below. "Economic benefits" are often referred to as "economic impacts," so that they are distinguished from other types of benefits. The net economic benefits include both the positive impacts of greater expenditures in Nevada and the negative impacts of higher electricity rates for consumers and businesses that generally accompany greater expenditures.

This section provides quantitative estimates and qualitative assessments that comply with the regulations discussed above.

The Companies retained the services of NERA to provide analyses of the environmental costs and net economic benefits for the two alternative resource cases for the Amendment.[52] Details on NERA's analyses of the two Amendment cases are provided in the NERA Report (Technical Appendix ECON-9).

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[49] NAC § 704.937(4).

[50] NAC § 704.9359.

[51] *Id.*

[52] NERA is a global firm of experts who apply economic, finance, and quantitative principles to complex business and legal challenges. NERA has earned wide recognition for its work in energy, environmental economics and regulation, antitrust, public utilities regulation, transportation, health care, and international trade, among other areas of expertise. References to NERA in this document relate to the authors of the NERA Report, Dr. David Harrison, Project Director; the analyses and conclusions in the NERA Report represent those of the authors and do not necessarily represent those of NERA or any of its clients.

2. Carbon Dioxide Price Scenarios

Background

On October 23, 2015, the U.S. Environmental Protection Agency ("EPA") published the final Clean Power Plan ("CPP") rule to regulate CO_2 emissions from existing fossil fuel-fired power plants under Section 111(d) of the Clean Air Act. The CPP would have taken effect in 2022 and included the possibility of a cap-and-trade program for state implementation of the CPP, based on the flexibility such implementation would give to minimize the costs of meeting emission reduction requirements. In response to litigation challenging EPA's promulgation of the CPP, on February 9, 2016, the Supreme Court "stayed" implementation of the CPP.

On March 28, 2017, President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which (among other provisions) called for a review of the CPP. On October 16, 2017, EPA formally proposed to repeal the CPP after completing its review. On August 21, 2018, EPA proposed a new rule to reduce greenhouse gas emissions from power plants entitled the Affordable Clean Energy ("ACE") rule, to replace the CPP. The ACE Rule, which was finalized on July 8, 2019, provided guidelines for states to develop emission standards for existing electricity generation units, with no provision for state implementation via a cap-and-trade program for GHG emissions from power plants. In 2019, a number of groups filed lawsuits challenging the lawfulness of the ACE rule.

The Biden administration indicated its intention not to defend the ACE Rule from litigation, and in January 2021, the U.S. Court of Appeals vacated the rule. The Biden administration has not, however, yet announced any proposal to replace the ACE Rule with another program to implement Section 111(d) of the Clean Air Act to regulate electric utility greenhouse gas emissions. There are some indications, however, that the Biden administration would favor the flexibility of an emissions trading approach. As one indication, President Biden's American Jobs Plan, announced March 31, 2021, included an Energy Efficiency and Clean Electricity Standard ("EECES") to achieve 100 percent clean power by 2035, including nuclear and hydropower as "clean" sources of electricity. This and other reasons suggest that a future regulation to reduce CO_2 emissions from the utility sector could include the cost-saving flexibility of a cap-and-trade approach.

Carbon Price Trajectory Used in These Analyses

In order to account for the range of possible future policies affecting electric sector CO_2 emissions, NERA developed several alternative CO_2 regulatory scenarios, one of which would involve no federal price on CO_2 emissions from power plants ("No CO_2 Price" scenario) and three of which would involve establishing national cap-and-trade programs to regulate electric utility emissions under Section 111(d) of the Clean Air Act, as a means of reducing the overall cost of meeting emission reduction requirements. The three scenarios have varying stringencies, leading to different trajectories for CO_2 allowance prices.

NERA developed the full set of results for a "Mid CO_2 Price" scenario, in which a national cap-and-trade program to implement regulation of power plant emissions is assumed to be put in place, with a cap trajectory consistent with allowance prices assumed to begin in 2027 at $25 per metric ton (2021$) and increase each year at a 5 percent real rate. NERA also developed estimates of the effects of the Mid CO_2 Price scenario on relevant fuel prices (natural gas and coal) after incorporating the Companies' baseline fuel price forecasts. The Companies used these estimated effects on fuel prices, as well as the CO_2 allowance prices, in its modeling of the two Amendment cases. These CO_2 allowance prices and the fuel price impacts lead to changes in the generation of various units under the two cases.

3. Environmental Costs for Conventional and toxic Air Emissions

NERA uses a damage value approach to develop estimates of the environmental costs of conventional and toxic air emissions. This approach begins with the premise that the conceptually correct measure of the value of pollutant emissions is equal to the value of the damages caused by those emissions (assuming no binding cap-and-trade program or other price for emissions). Damages can include effects on health, visibility, and agriculture.[53] The empirical information used in this approach includes information developed by EPA based upon its summaries of research by environmental scientists and economists (although NERA has not validated this information).

Figure NERA-1 presents the estimated environmental costs of conventional and toxic air emissions for the two cases. The figure shows environmental costs for emissions controlled to meet National Ambient Air Quality Standards ("NAAQS") as well as emissions related to requirements of the Mercury and Air Toxics Standards ("MATS") issued by EPA in 2011. Based on the NAAQS, NERA included values for emissions of nitrogen oxides ("NO_x"), particulate matter ("PM"), volatile organic compounds ("VOC"), carbon monoxide ("CO"), and sulfur dioxide ("SO_2"). VOC environmental costs are estimated to be $0 because they do not contribute to ambient ozone concentrations in Nevada, as discussed in the NERA Report. CO is not monetized because the requisite air quality modeling data are unavailable; however, CO emissions projections are included in the NERA Report. As noted in the NERA Report, the national SO_2 cap is not expected to be binding and, thus, costs from SO_2 emissions are evaluated based on damage values like other air emissions (rather than modeled as covered by a cap-and-trade program as in some past IRPs). Based on their inclusion in the MATS regulation, emissions of mercury and hydrogen chloride ("HCl") are also included. The MATS regulation uses particulate matter ("PM") emissions as a proxy for non-mercury metallic air toxics, but this element of the MATS regulation does not lead to additional environmental costs because PM emissions are already included based upon the NAAQS. HCl is not monetized because EPA does not provide the relevant information in the MATS regulatory impact analysis; however, HCl emission projections are included in the NERA Report. NERA does not expect that including costs for the other pollutants, if they could be estimated, would have any significant effects on the estimates of the environmental costs of conventional and toxic air emissions.

[53] Given data limitations, NERA did not quantify non-health welfare effects but indicated that they expect non-health costs to be small relative to the health damages.

FIGURE NERA-1
PRESENT VALUES OF ENVIRONMENTAL COSTS FOR CONVENTIONAL AIR EMISSIONS AND AIR TOXICS, 2022-2051 (2022$ MILLIONS)

	Preferred	Alternate	Difference (Alternate - Preferred)
NOx	$1.32	$1.33	$0.01
PM	$56.56	$57.16	$0.60
VOC	$0.00	$0.00	$0.00
CO	--	--	--
SO2	$2.33	$2.32	-$0.01
Mercury	$0.00	$0.00	$0.00
HCl	--	--	--
Total	**$60.21**	**$60.81**	**$0.60**

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by the Companies. Total may differ from the sum of the rows due to independent rounding. "-" denotes that the environmental costs of the air emission or air toxic are not monetized. The costs of VOC emissions are zero because of evidence that these emissions do not contribute to urban ozone, the relevant damage category. The costs of mercury emissions round to zero when reported in millions, as the present values are less than $1,000 for both Amendment cases.

Source: NERA calculations as explained in text.

Figure NERA-1 also shows the differences in environmental costs for conventional air emissions and air toxics for the Alternate Plan relative to the Preferred Plan. These results indicate that the Alternate Plan has greater conventional and toxic air emissions costs than the Preferred Plan by about $600,000.

4. Social Cost of Carbon for Carbon Dioxide Emissions

NERA developed estimates of the social cost of carbon for the two cases using estimates of the CO_2 emissions for each of the cases and the valuation methodology required by the Commission in its August 2018 Order.

a. Estimates of Carbon Dioxide Emissions

NERA developed estimates of carbon dioxide emissions over time for the two cases using information from modeling done by the Companies and from other sources. Figure NERA-2 provides these estimates for the two resource cases, with Figure NERA-3 showing percent differences for the Alternate Plan relative to the Preferred Plan.

FIGURE NERA-2
CARBON DIOXIDE EMISSIONS, 2022-2051 (MILLIONS OF METRIC TONS)

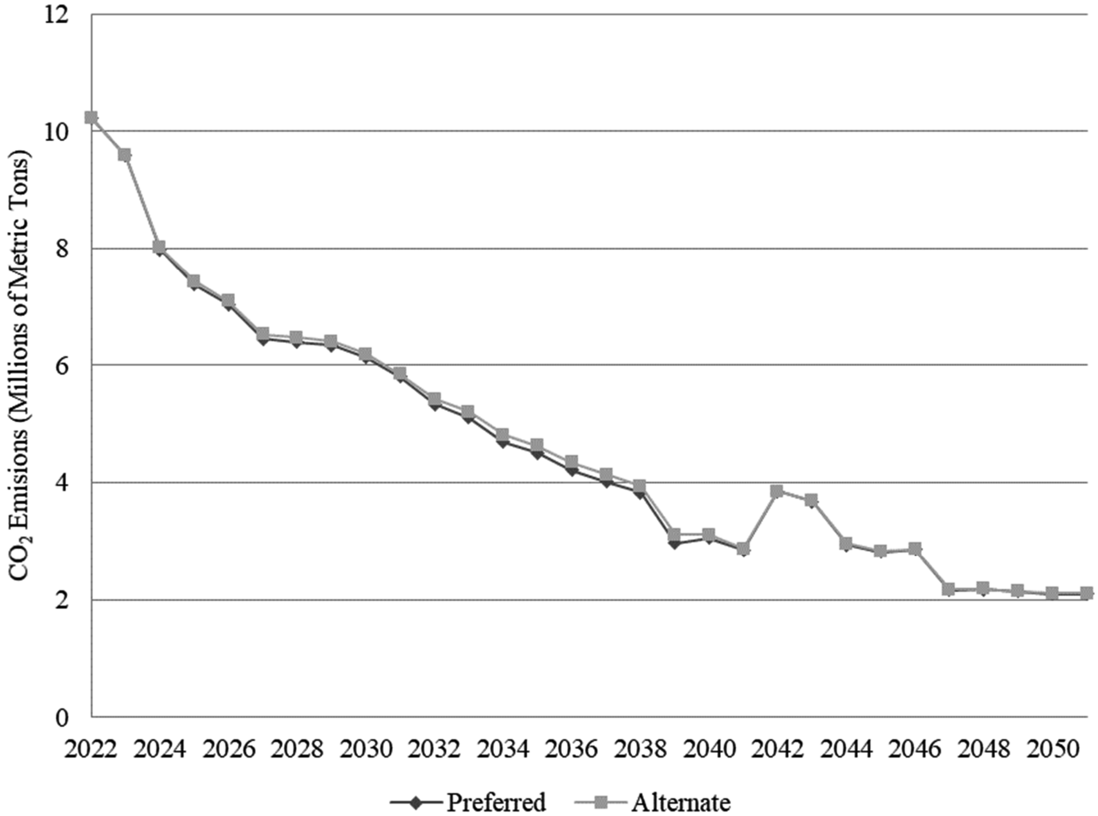
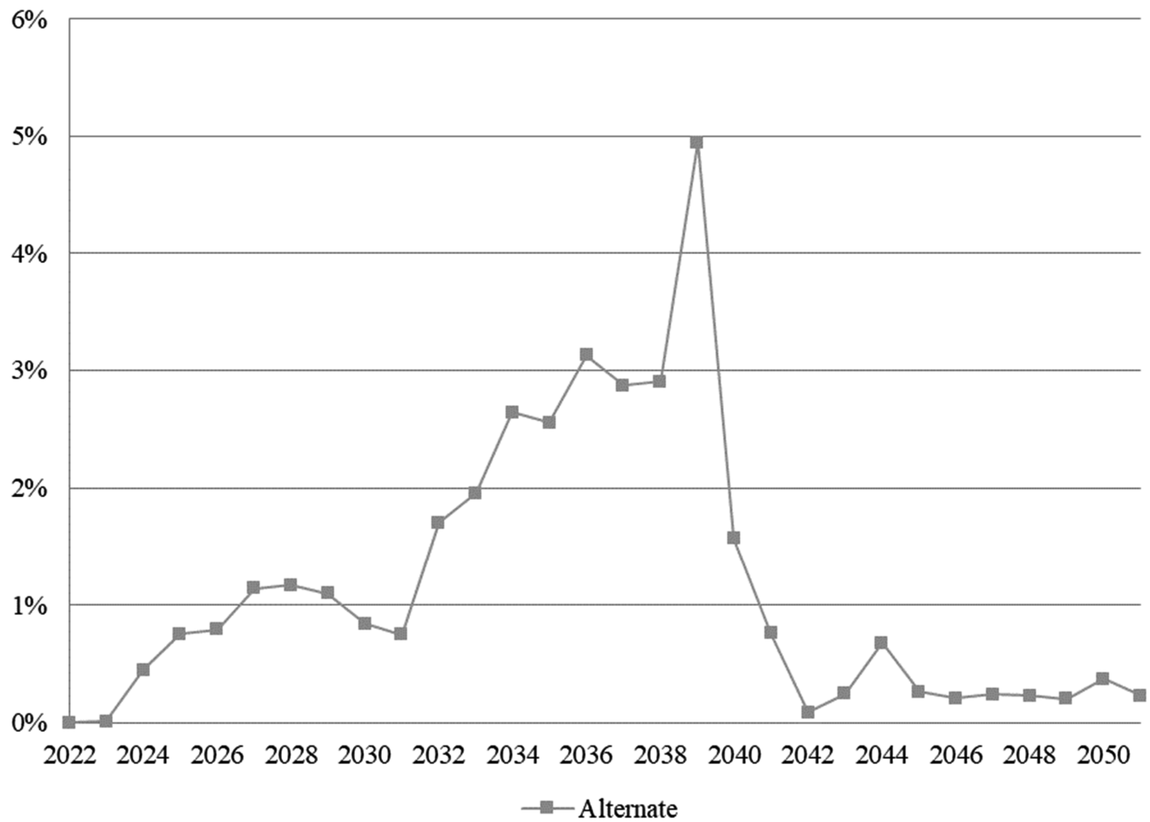


FIGURE NERA-3
PERCENTAGE DIFFERENCE IN CARBON DIOXIDE EMISSIONS FOR THE ALTERNATE PLAN RELATIVE TO THE PREFERRED PLAN, 2022-2051



b. Methodology Required by the Commission to Value Carbon Dioxide Emissions

Subsection 5 of the Commission's August 2018 Order requires that "the social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the 'Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis' released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016."[54]

[54] There is some potential confusion in use of the term "social cost of carbon." The term is used by the Interagency Working Group (as well as many commentators) to refer to its estimates; but these estimates are referred to by the Commission in its August 2018 Order as the "future global economic costs." The Commission in its August 2018 Order refers to the social cost of carbon as the difference between future global economic costs and the costs internalized as private costs (in this case the allowance prices). NERA adopts the terminology of the August 2018 Order in its current report (although some previous reports have used "social cost of carbon" to refer to the values developed by the Interagency Working Group). The current NERA Report provides information on the methodology

The Interagency Working Group provided estimates of future global economic costs from an additional ton of carbon dioxide for three discount rates—2.5 percent, 3 percent, and 5 percent—using the average of the damages distribution it calculated from modeling results. It also provided a fourth set of global economic costs based on the 3 percent discount rate and the 95th percentile of the damages distribution, which it noted are designed "to represent the higher-than-expected impacts from temperature change further out in the tails of the [global economic cost] distribution" (Interagency Working Group 2015, p. 2). These four sets of values cover a very large range and, indeed, the full range of values reported by the Interagency Group was much greater than these four sets of estimates.

NERA used its estimates of future allowance prices under the Mid CO_2 Price scenario as measures of the costs of CO_2 emissions that are internalized as private costs to the utility; this approach is consistent with the Companies' use of these prices in the PROMOD modeling. In compliance with the August 2018 Commission Order, NERA calculated the social cost of carbon based on the global environmental cost values in the most recent report of the Interagency Working Group (Interagency Working Group 2021)—based on a 3 percent discount rate and the average of the damages distribution—minus the allowance prices in the Mid CO_2 Price scenario.

c. Social Costs of Carbon

Figure NERA-4 shows the estimates of the social costs of carbon (as present values) for the two plans, and also shows the difference in the social costs of carbon for the Alternate Plan relative to the Preferred Plan. The social costs of carbon are greater for the Alternate Plan than for the Preferred Plan by about $53 million.

FIGURE NERA-4
PRESENT VALUES OF SOCIAL COSTS OF CARBON AND DIFFERENCES IN PRESENT VALUES RELATIVE TO THE PREFERRED PLAN, 2022-2051
(2022$ MILLIONS)

Preferred	Alternate	Difference (Alternate - Preferred)
$5,291	$5,344	$53

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 based on values reported by Interagency Working Group (2021) and the allowance price projections for the Mid CO_2 Price scenario. The values reflect a 3 percent annual discount rate for global economic costs.
Source: NERA calculations as explained in text.

NERA has in prior IRPs noted that the global values developed by the Interagency Working Group are not comparable to the environmental costs calculated for air and toxic emissions for several reasons: (a) the Interagency Working Group values are more uncertain partly because they are based upon impacts in the distant future; (b) the Interagency Working Group values are based on

used by the Interagency Working Group to develop its estimates and on the wide range of estimates that are provided in the February 2021 report (See Section III.B of NERA Report), which updates the August 2016 report for inflation.

different discount rates than the private (NV Energy) discount rates used to calculate the present value of the other environmental costs; and (c) the Interagency Working Group values are based upon global damages rather than U.S. damages.

5. External Costs of Water Consumption

NERA estimated the costs of water consumption by the Companies that are not included in the PWRR. These additional costs are based upon current information related to water use from wells owned by the Companies and do not include water that is leased or purchased, because the value of leased or purchased water is included in the PWRR. Moreover, no additional water costs are calculated for power purchased by the Companies through contracts, renewable power purchase agreements, or spot market transactions because NERA assumes that all water costs will be included in the product rate paid by the Companies, and thus, in the PWRR.

Figure NERA-5 shows the estimated additional costs of water consumption (i.e., the added costs beyond those already included in the PWRR) for the two resource cases as well as the differences between the Alternate Plan and the Preferred Plan, calculated as present values over the 30-year period from 2022 to 2051 as of 2022. The Alternate Plan has smaller external water costs than the Preferred Plan by about $100,000 due to the Alternate Plan's somewhat smaller generation at facilities that use water from wells owned by the Companies.

FIGURE NERA-5
PRESENT VALUE OF ADDITIONAL WATER COST, 2022-2051 (2022$ MILLIONS)

Preferred	Alternate	Difference (Alternate - Preferred)
$10.7	$10.6	-$0.1

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051 using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

6. Other Environmental Effects

NERA considered three other categories of environmental impacts: (1) land use; (2) water quality; and (3) solid waste disposal, including sludge and ash disposal. For all three categories, NERA considered whether or not there might be significant differences in environmental costs among the resource cases. NERA concluded than any cost differences were likely to be highly site-specific and were not likely to be significant relative to the estimated environmental costs.

7. Present Worth of Societal Cost

Figure NERA-6 provides information on the PWSC for the two resource cases. As noted above, PWSC is defined as the sum of the PWRR and the environmental costs. Figure NERA-6 also shows the PWSC values for the Alternate Plan relative to the Preferred Plan. These results indicate that the PWSC is lower for the Preferred Plan than for the Alternate Plan by about $108.2 million, with the difference due primarily to the lower PWRR and the lower social cost of carbon for the Preferred Plan than for the Alternate Plan.

FIGURE NERA-6
PRESENT WORTH OF SOCIETAL COSTS, 2022-2051 (2022$ MILLIONS)

	Preferred	Alternate	Difference (Alternate- Preferred)
PWRR	$27,745.2	$27,800.2	$55.0
Conventional Air Emission Costs	$60.2	$60.8	$0.6
Additional Water Costs	$10.7	$10.6	-$0.1
Social Costs of Carbon	$5,291.4	$5,344.1	$52.7
PWSC	$33,107.5	$33,215.7	$108.2

Notes: All values are present values as of 2022 in millions of 2022 dollars for the period 2022-2051. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.14 percent for Nevada Power and 6.75 percent for Sierra. The SCC values reflect a 3 percent annual discount rate for global economic costs.

Source: NERA calculations as explained in text.

8. Economic Impacts

The NERA economic impact analysis uses the economic model developed by Regional Economic Models, Inc. ("REMI") to develop comprehensive estimates of economic impacts for the two Amendment cases, including the positive effects of greater expenditures in Nevada as well as the potential negative effects of greater electricity rates under more expensive cases. The Companies provided NERA with information on the two Amendment cases that enabled NERA to estimate both the positive economic impacts of expenditures associated with the two resource cases and the negative economic impacts of the electricity rate increases associated with these expenditures. These analyses are based primarily on the costs and revenue requirements related to the Companies' bundled customers and do not include costs and revenues related to entities that purchase transmission capacity from the Companies ("transmission-only customers"), as the PWRR cost information generally is based on bundled customers. The only exception is that the costs and revenue requirements include those related to provision of 90 megawatts of additional reserve capacity for transmission-only customers, information that is included in the PWRR.

9. REMI Model

As explained in detail in the NERA Report, the REMI model provides a detailed representation of the Nevada economy. The core of the model is a set of input-output ("I/O") relationships among different industries that allow one to estimate how changes in demand or supply in each relevant industry will affect all other industries. The I/O formulation also includes "economic leakage," which is the extent to which expenditures in any industry lead to imported goods from outside the economy (and thus do not have "multiplier" effects in Nevada). REMI also provides estimates of the impacts on Nevada when feedback mechanisms in the economy are included (e.g., changes in wages that result from changes in economic activity and thus in the demand for labor).

Simulations of the economy in REMI require a "baseline" scenario to which "alternative" scenarios can be compared. The Companies developed a Base Case that is assumed to reflect the REMI baseline or reference scenario. The economic impact analysis is conducted over the period from 2022 to 2051, which is the period over which the Companies forecast expenditures and revenues. NERA developed economic impact assessments for the two Amendment cases relative to the Base Case. Although the Base Case is assumed to be the baseline or reference scenario for purposes of the REMI modeling, results are presented for the Alternate Plan relative to the Preferred Plan, the same format as for the environmental cost comparisons.

Expenditures, Revenues and Economic Impacts

Figure NERA-7 shows the average annual expenditures in Nevada under the three cases, including the two Amendment cases and the Base Case. The table includes construction expenditures, fuel expenditures and non-fuel operating and maintenance ("O&M") expenditures. Only expenditures that occur in Nevada are included in these calculations because of the focus on estimating the economic impacts in Nevada. Note that these average annual values do not reflect differences over the 30-year period, differences that are included in the REMI modeling. As discussed in the NERA Report, the expenditures exclude certain categories of expenditures, such as market purchases by the Companies, because those expenditures are assumed to be from power producers outside Nevada (and thus the expenditures would not generate significant positive economic impacts in Nevada). NERA assumes that 50 percent of open position expenditures would occur within the state and that 50 percent of these expenditures would occur outside Nevada.

FIGURE NERA-7
AVERAGE ANNUAL TOTAL EXPENDITURES, 2022-2051 (2022$ MILLIONS)

	Base	Preferred	Alternate
Construction	$1,476	$1,481	$1,479
Fuel	$349	$343	$347
O&M	$372	$377	$379
Total	**$2,197**	**$2,201**	**$2,205**

Note: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

Figure NERA-8 shows the differences in average annual expenditures over the period from 2022 to 2051 for the two resource cases relative to the Base Case; the differences in each year relative to the Base Case are the values that are included in the REMI modeling, based upon detailed information to reflect the sectors directly affected by the expenditures in each year. The figure also shows the differences for the Alternate Plan relative to the Preferred Plan. This information indicates that on average, the annual construction expenditures are greater for the Preferred Plan and that the annual fuel expenditures and other operating and maintenance expenditures are greater for the Alternate Plan.

FIGURE NERA-8
AVERAGE ANNUAL TOTAL EXPENDITURES, RELATIVE TO THE BASE CASE, 2022-2051 (2022$ MILLIONS)

	Base	Preferred	Alternate	Difference (Alternate - Preferred)
Construction	-	$5	$3	-$2
Fuel	-	-$6	-$2	$4
O&M	-	$5	$7	$2
Total	**-**	**$4**	**$8**	**$4**

Note: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

Figure NERA-9 shows the average annual electricity revenue requirements for 2022-2051, apportioned by customer class (based on the methodology described in the NERA Report that combines information of Nevada Power and Sierra).

FIGURE NERA-9
AVERAGE ANNUAL ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS, 2022-2051 (2022$ MILLIONS)

	Base	Preferred	Alternate
Residential	$1,082	$1,085	$1,087
Commercial	$532	$534	$534
Industrial	$242	$243	$243
Total	**$1,856**	**$1,863**	**$1,865**

Note: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

Figure NERA-10 shows differences in average annual values of electricity revenue for each of the two Amendment cases relative to the Base Case (the REMI baseline). The differences in each year are the values that are included in the REMI modeling, based on detailed information to reflect the direct impacts on the three sets of customers in each year. This information indicates that on average, the annual revenue requirements are the same for industrial customers and greater for the Alternate Plan than for the Preferred Plan for residential and commercial customers.

FIGURE NERA-10
ELECTRICITY REVENUE BY CUSTOMER CLASS, RELATIVE TO THE BASE CASE, 2022-2051 (2022$ MILLIONS)

	Base	Preferred	Alternate	Difference (Alternate - Preferred)
Residential	-	$3	$5	$2
Commercial	-	$2	$3	$1
Industrial	-	$1	$1	$0
Total	**-**	**$7**	**$9**	**$2**

Note: All values are average annual values over the period from 2022 to 2051 in millions of 2022 dollars. Dollar year conversions are based on inflation rate information, as provided by the Companies.
Source: NERA calculations as explained in text.

REMI modeling takes as inputs the annual expenditures and electricity revenues relative to the Base Case and develops economic impacts for the two Amendment cases over time. The NERA Report describes the methodologies that are used to translate the expenditure and revenue requirement categories into the annual REMI inputs that NERA uses when it runs the REMI model over the 30-year period from 2022-2051.

Figure NERA-11 provides estimates of the differences in economic outcome measures for selected years in Nevada for the two Amendment cases relative to the Base Case as well as the differences in impacts for the Alternate Plan relative to the Preferred Plan. The relative economic impacts of the two plans vary over the selected years in the 30-year period from 2022-2051, reflecting the different timing of construction and other major initial changes in economic activity.

FIGURE NERA-11
ECONOMIC IMPACTS, RELATIVE TO THE BASE CASE, 2022-2051

	Nevada Economic Impact						
	2022	**2023**	**2024**	**2025**	**2035**	**2045**	**2051**
Base							
Gross State Product (millions of 2022 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2022 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2022 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
Preferred							
Gross State Product (millions of 2021 dollars)	42.0	114.0	15.0	5.0	-3.0	1.0	1.0
Personal Income (millions of 2021 dollars)	26.0	70.0	5.0	1.0	-1.0	3.0	2.0
State & Local Tax Revenue (millions of 2021 dollars)	2.60	7.00	0.50	0.10	-0.10	0.30	0.20
Employment (total jobs)	445	1,181	139	18	2	30	23
Alternate							
Gross State Product (millions of 2022 dollars)	15.0	105.0	48.0	9.0	-5.0	2.0	3.0
Personal Income (millions of 2022 dollars)	9.0	66.0	26.0	0.0	-2.0	4.0	4.0
State & Local Tax Revenue (millions of 2022 dollars)	0.90	6.60	2.60	0.00	-0.20	0.40	0.40
Employment (total jobs)	169	1,130	537	42	-8	44	38
Difference (Alternate - Preferred)							
Gross State Product (millions of 2022 dollars)	-27.0	-9.0	33.0	4.0	-2.0	1.0	2.0
Personal Income (millions of 2022 dollars)	-17.0	-4.0	21.0	-1.0	-1.0	1.0	2.0
State & Local Tax Revenue (millions of 2022 dollars)	-1.7	-0.4	2.1	-0.1	-0.1	0.1	0.2
Employment (total jobs)	-276	-51	398	24	-10	14	15

Notes: The Base Case is assumed to be consistent with the REMI Baseline scenario, and thus results are reported relative to the Base Case. The final rows show results for the Alternate Plan relative to the Preferred Plan.
Employment values include full time and part time jobs.

Sources: REMI; NERA calculations as explained in text.

FIGURE NERA-12 provides estimates of the average annual economic impacts in Nevada over the 30-year period from 2022-2051 for the two Amendment cases relative to the Base Case as well as the differences in average annual impacts for the Alternate Plan relative to the Preferred Plan. These results indicate that, on average, the annual impacts are greater for the Alternate Plan than the Preferred Plan by about $200,000 for gross state product and by about 4 jobs for employment and smaller for the Alternate Plan than the Preferred Plan by about $100,000 for personal income and by about $10,000 for state and local tax revenue.

FIGURE NERA-12
ANNUAL AVERAGE ECONOMIC IMPACTS, RELATIVE TO THE PREFERRED PLAN

	Base	Preferred	Alternate	Difference (Alternate - Preferred)
Gross State Product (millions of 2022 dollars)	-	3.4	3.6	0.2
Personal Income (millions of 2022 dollars)	-	2.4	2.3	-0.1
State & Local Tax Revenue (millions of 2022 dollars)	-	0.24	0.23	-0.01
Employment (total jobs)	-	48	52	4

Notes: The Base Case is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs thus are modeled for the two Amendment cases in comparison to the Base Case and results are reported relative to the Base Case. Employment values include full time and part time jobs.
Sources: REMI; NERA calculations as explained in text.

I. Selection of the Preferred Plan

The following criteria was used when selecting the "All Generator Upgrades + North Valley + 2-Hr BESS" plan as the Preferred Plan and the "All Generator Upgrades + North Valley + CT" plan as the Alternate Plan.

1. **The Companies' intent to reduce the risk of exposure to the uncertain availability of market capacity**
   As described in the introduction to this Amendment, recent events and reports contribute to ever decreasing confidence in the availability of market capacity. While the 2021 Joint IRP reduced the reliance on market capacity relative to prior plans, there is concern that further reduction is required to reduce risk and ensure resource adequacy. This Amendment takes advantage of all that has been set in motion and further addresses increasing concerns regarding the availability of market capacity as it is impacted by changes in climate, weather, and resource variability across the region. While both plans proposed in this Amendment take great efforts to reduce the near term exposure to market capacity, the "All Generator Upgrades + North Valley + 2-Hr BESS" plan is able to achieve a greater reduction sooner, due to the earlier in-service date of the 2-Hour BESS relative to the Silverhawk CT.

2. **PWRR and PWSC results**
   While the costs of the two plans proposed in this Amendment are not that dissimilar, the "All Generator Upgrades + North Valley + 2-Hr BESS" plan has a lower PWRR and PWSC than the "All Generator Upgrades + North Valley + CT" plan.

3. **The Companies' and state's decarbonization goals**
   While both plans presented in this Amendment add a diverse renewable resource in the form of the North Valley geothermal project and achieve the state's 2050 clean energy goal, the "All Generator Upgrades + North Valley + 2-Hr BESS" plan moves the decarbonizing needle further sooner and increases diversity in the form of a 2-hour BESS project.

While the "All Generator Upgrades + North Valley + CT" plan benefits from the stable capacity of the Silverhawk CT project rather than the declining ELCC of the 2-hour BESS project, it is a higher cost plan. Ultimately, early reduction of the Open Position, cost, and consistency with decarbonizing goals led the Companies to select the "All Generator Upgrades + North Valley + 2-Hr BESS" Plan as the Preferred Plan when balancing the objectives listed above.

Due to an opportunity to install the Sun Peak wet compression project prior to summer 2022, as described in the Generation narrative, this project, which is one of the generator upgrades included in both the Preferred Plan and the Alternate Plan, is not being requested in this Amendment.

SECTION 9. FINANCIAL PLAN

A. Introduction

The following section summarizes the results of the analysis of financial impacts of the Preferred and Alternate Plans presented in this Amendment. The Financial Plan for both Nevada Power and Sierra spans a 20-year period (2023-2042) and analyzes these two scenarios from the perspective of customers and the Companies using several financial metrics as mandated by NAC § 704.9401(1). Also included in the Financial Plan, for both utilities, are descriptions of the financial forecasting assumptions and common methodologies used to prepare the Financial Plan.

B. Capital Expenditures

The capital expenditures and cash flow analysis prepared for the Financial Plan utilize the CER model (described in the Economic Analysis section above) for the Preferred and Alternate Plans. Figure FP-1 below compares Nevada Power's total capital expenditures (including AFUDC) for both plans on a yearly basis over the planning period. Capital expenditures for Nevada Power for the 20-year period are estimated to total $10.7 billion for the Preferred Plan and $10.8 billion for the Alternate Plan. For Sierra, capital requirements shown in Figure FP-2 are estimated to total $5.2 billion for the Preferred and Alternate Plans. Additional project details can be found in the Economic Analysis section above.

FIGURE FP-1
NEVADA POWER
CAPITAL EXPENDITURES ($ - MILLIONS)
(Including AFUDC)

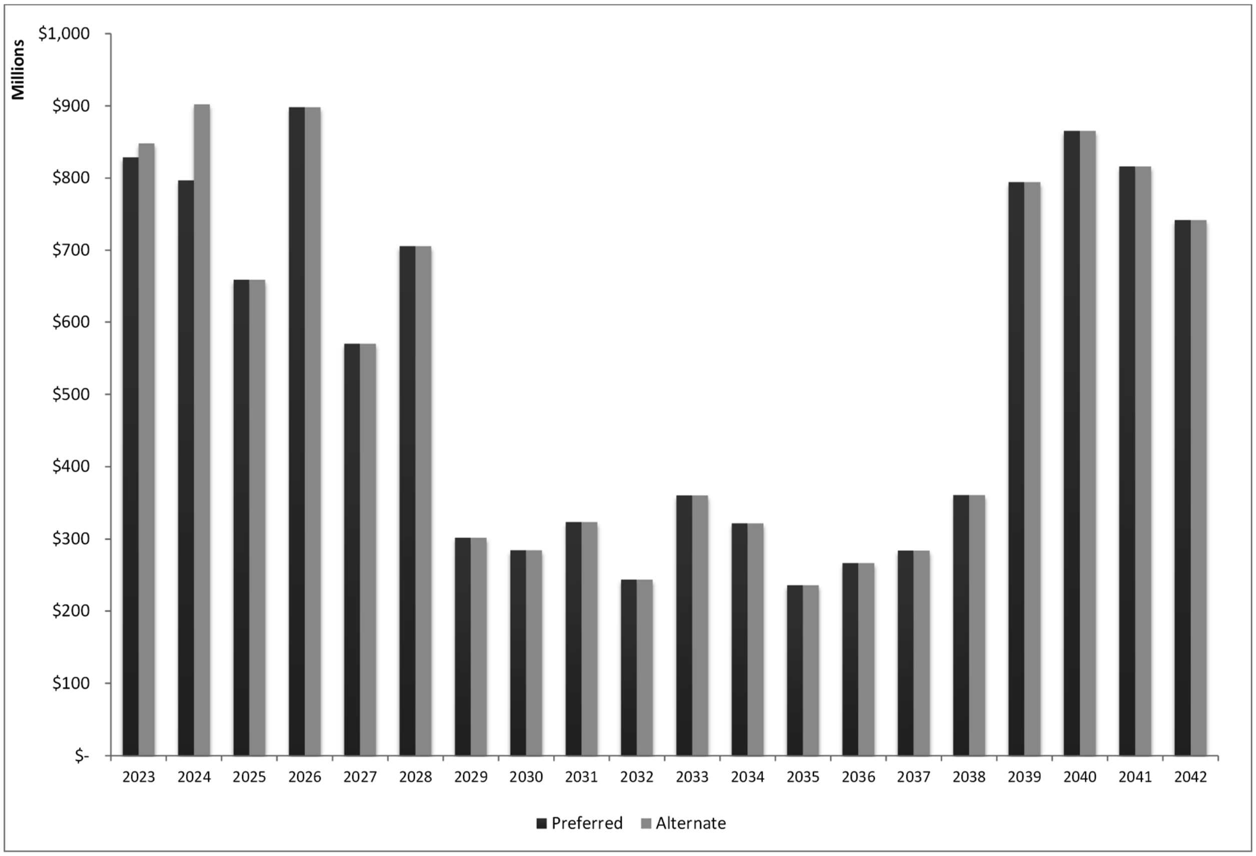
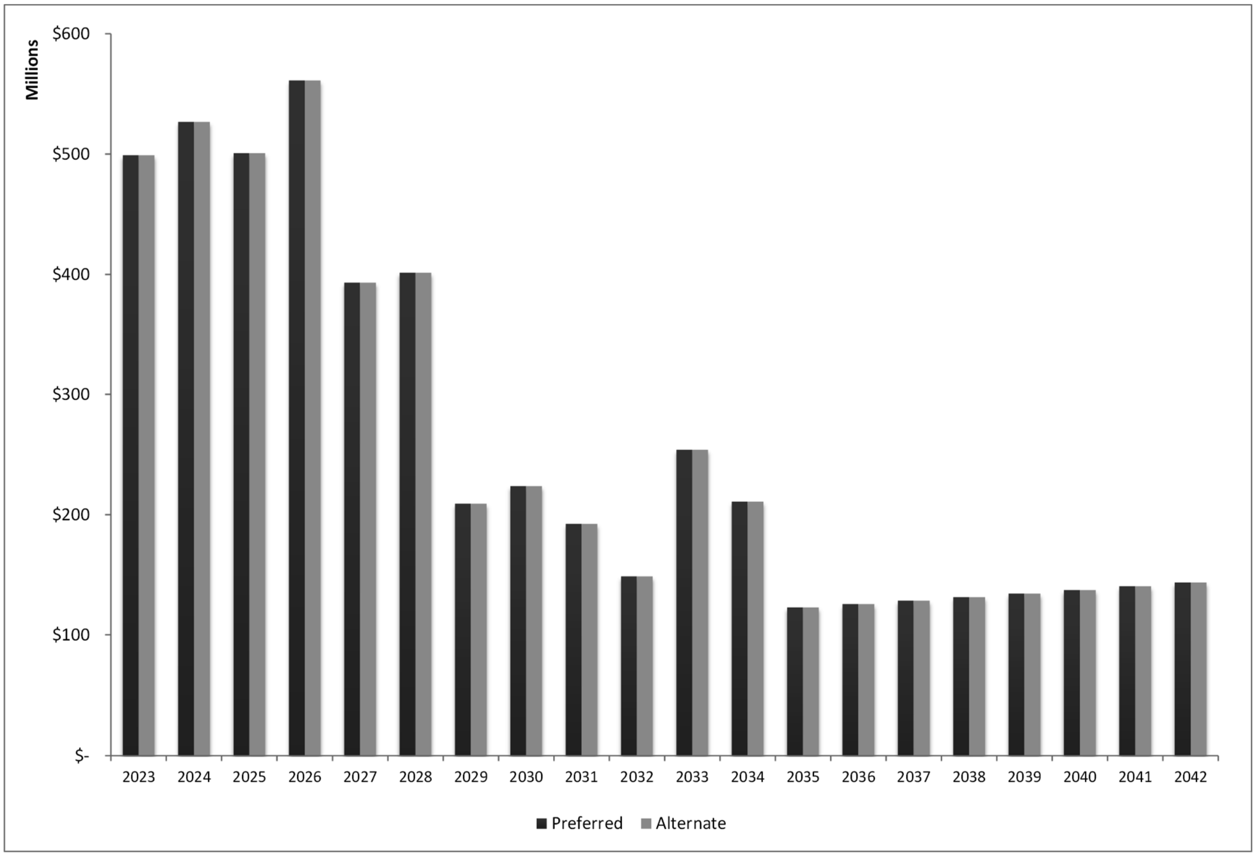


FIGURE FP-2
SIERRA
CAPITAL EXPENDITURES ($ - MILLIONS)
(Including AFUDC)



C. External Financing Requirements

For the majority of the years during the 2023-2042 period, cash generated from operations at both utilities is in excess of the capital projects set forth in the CERs for the Preferred and Alternate Plans. The amount of capital in Sierra's Preferred and Alternate Plans may create some additional challenges to credit metrics in the near term; however, the incremental capital associated with the Preferred and Alternate Plans represents a small percentage of the total capital over the 2023-2042 period and the associated impacts on credit metrics is not expected to be material. The Companies will have a continued need to access external short- and long-term financing in order to finance capital projects and working capital, refinance maturing debt, and maintain capital structures that are appropriate for their investment grade credit ratings. This ongoing need to access external capital at attractive rates requires regulatory support and continued reliance on financial markets. For Nevada Power, Figure FP-3 depicts annual total external debt requirements over the forecast horizon for the Preferred and Alternate Plans, respectively. External financing requirements for Nevada Power for the 20-year period are estimated to total [redacted] for the Preferred and Alternate Plans. For Sierra, external debt financing projections are shown in Figure FP-4 and are estimated to total [redacted] for the Preferred Plan and [redacted] for the Alternate Plan.

FIGURE FP-3
NEVADA POWER - (CONFIDENTIAL)
SUMMARY OF EXTERNAL DEBT FINANCING
($ - MILLIONS)

[redacted]

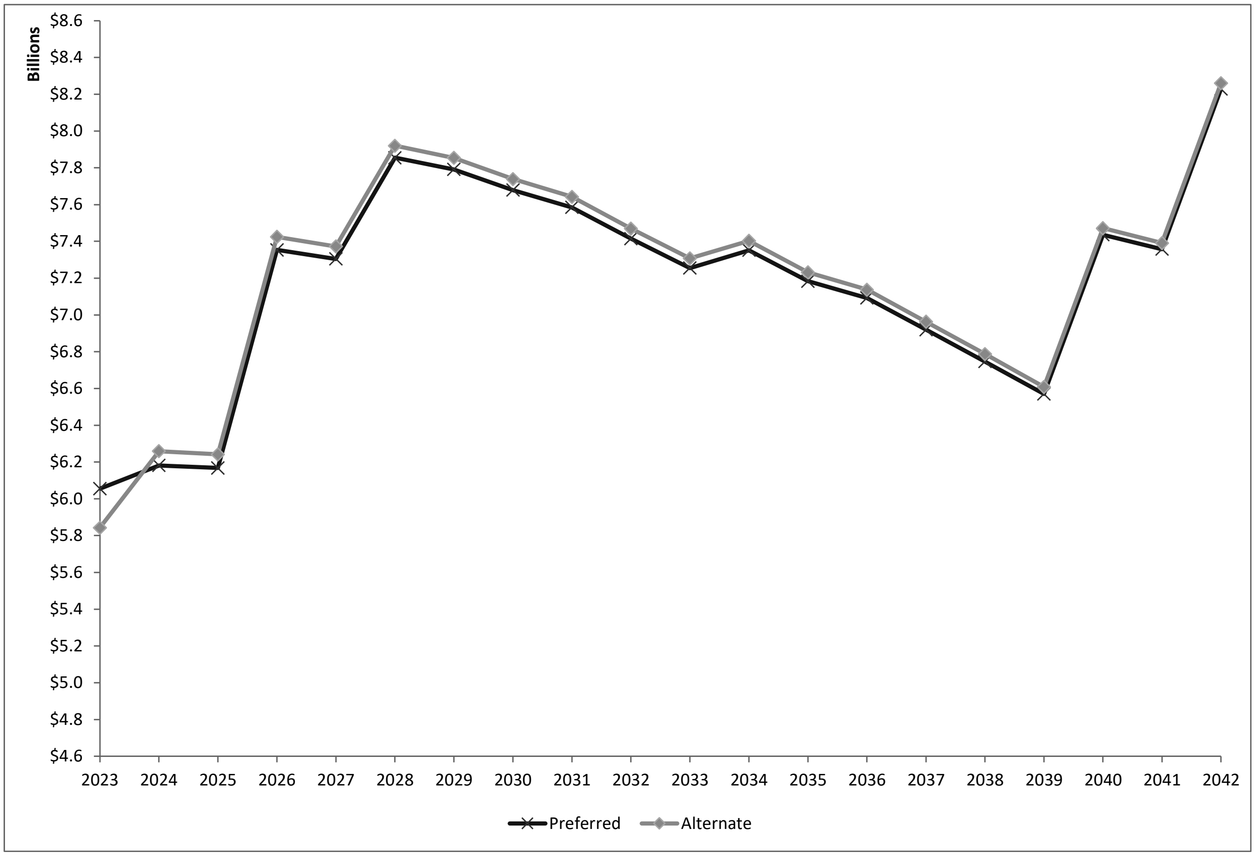
FIGURE FP-4
SIERRA - (CONFIDENTIAL)
SUMMARY OF EXTERNAL DEBT FINANCING
($ - MILLIONS)

[redacted]

D. Total Rate Base

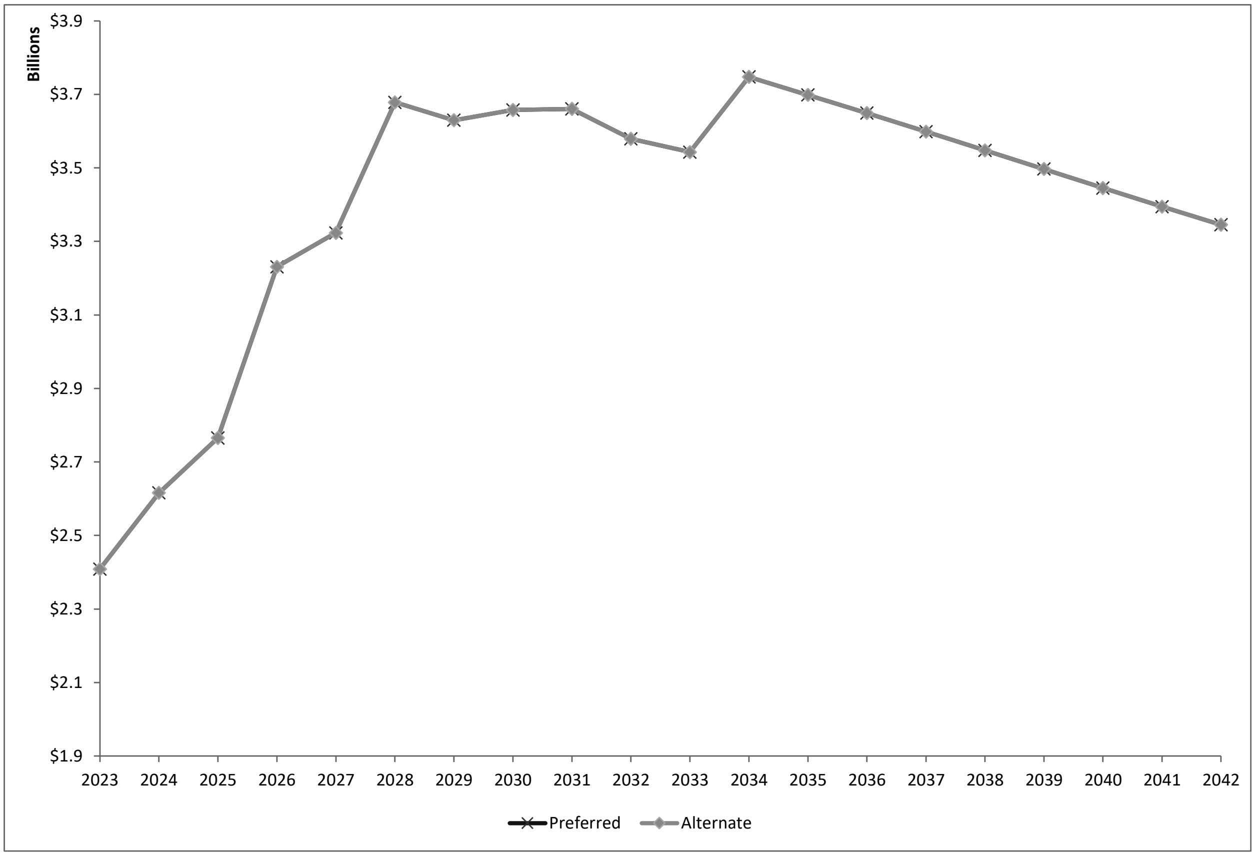
For Nevada Power, Figure FP-5 below compares total rate base per year over the planning period. Compound annual growth rates for rate base over the planning period total 1.5 percent for the Preferred Plan and 1.7 percent for the Alternate Plan. The significant increase in rate base starting in 2040 for the Preferred and Alternate Plans is attributable to the inclusion of additional dispatchable resources.

FIGURE FP-5
NEVADA POWER
ELECTRIC RATE BASE
($ - BILLIONS)



For Sierra, Figure FP-6 below compares total electric rate base per year over the 20-year planning period. Compound annual growth rates for rate base over the planning period total 1.7 percent for the Preferred and Alternate Plans.

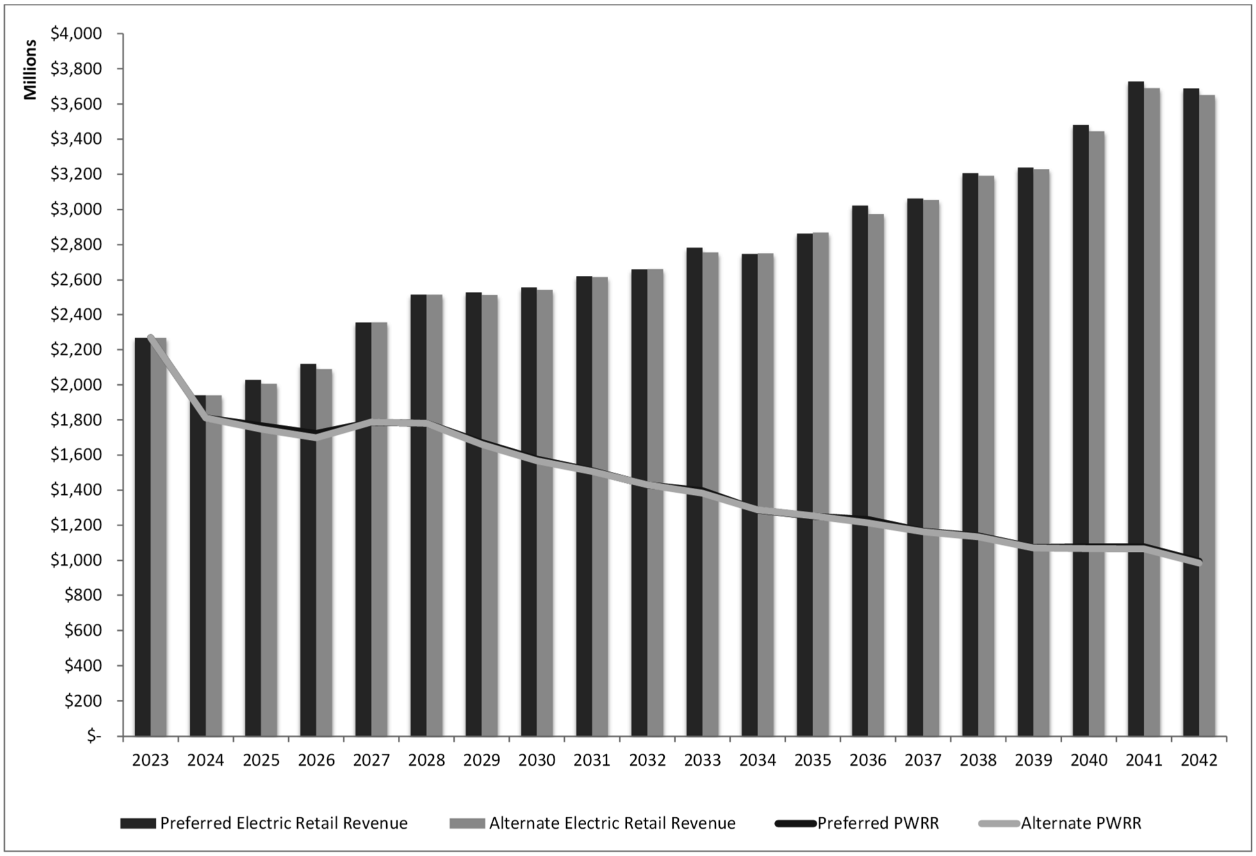
FIGURE FP-6
SIERRA
ELECTRIC RATE BASE
($ - BILLIONS)



E. Electric Revenue

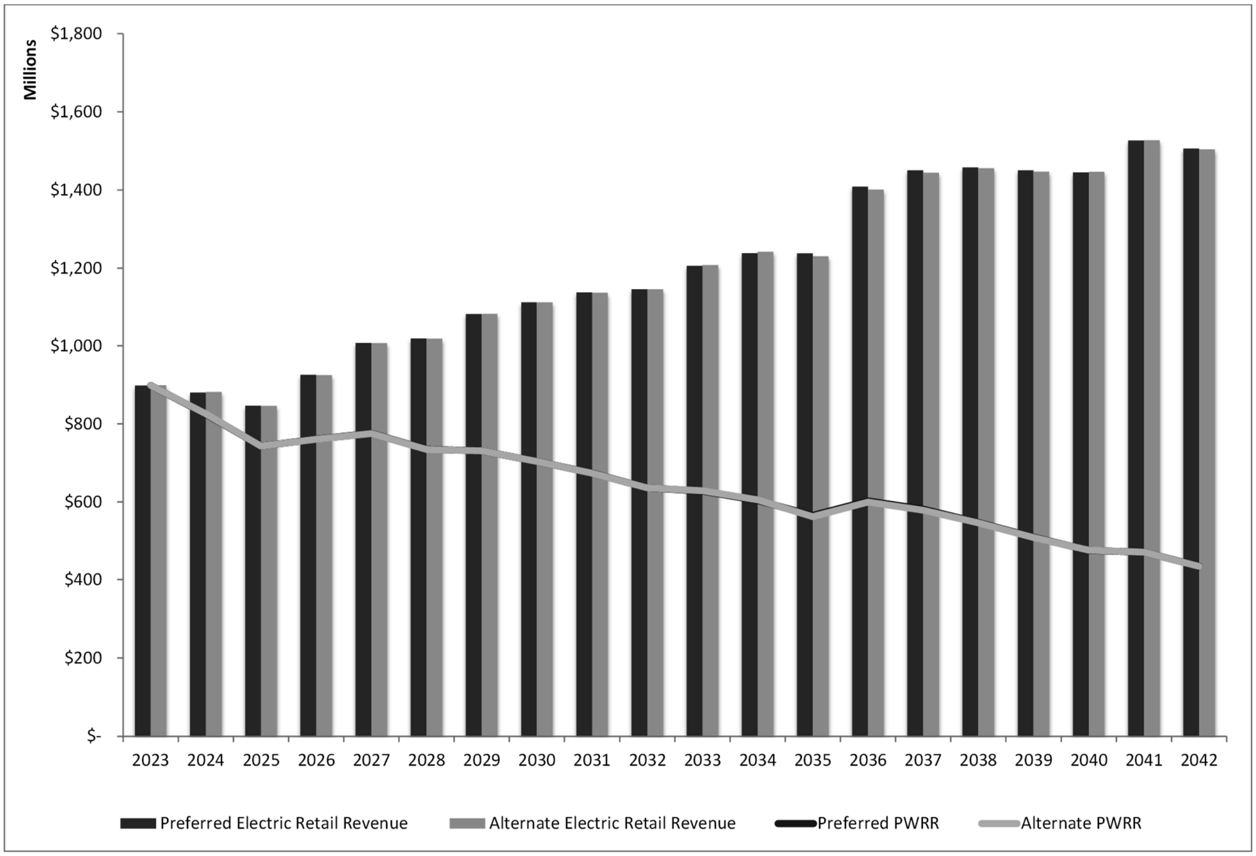
During the 20-year planning period, the Preferred Plan for Nevada Power results in a compound annual growth rate in electric retail revenue (including fuel costs) of 2.5 percent (from approximately $2.3 billion to $3.7 billion). The Alternate Plan for Nevada Power results in a compound annual growth rate in electric retail revenue (including fuel costs) of 2.4 percent (from approximately $2.3 billion to $3.7 billion). Figure FP-7 shows estimated annual total electric revenue (in nominal dollars) for Nevada Power for the planning period as well as its present worth.

FIGURE FP-7
NEVADA POWER
TOTAL RETAIL ELECTRIC REVENUES AND PRESENT WORTH
($ - MILLIONS)



For Sierra, the Preferred and Alternate Plans result in a compound annual growth rate in electric retail revenue (including fuel costs) of 2.6 percent (from approximately $0.9 billion to $1.5 billion). Figure FP-8 shows estimated annual total electric revenue (in nominal dollars) for Sierra for the planning period as well as its present worth.

FIGURE FP-8
SIERRA
TOTAL RETAIL ELECTRIC REVENUES AND PRESENT WORTH
($ - MILLIONS)



F. Common Methodologies and Assumptions

The following section discusses the common methodologies and assumptions used in forecasting and evaluating the financial impact of the Amendment.

1. <u>Common Methodologies</u>

The financial analysis was performed using the Companies' financial forecasting model based on the Utilities International, Inc. ("UI") platform. The model uses many of the same inputs (e.g., capital expenditures or "CAPEX," AFUDC rate based at the Companies' authorized rates of returns, production costs, depreciation rates and load forecast) from the CERs that are utilized in the Economic Analysis section described earlier. Additional inputs include pro-forma capital structures and capital costs. The UI platform simulates general rate review proceedings on a timeline consistent with the schedule currently embodied in the Nevada Revised Statutes.

2. Assumptions

Major financial modeling assumptions for Nevada Power and Sierra are described below. Unless noted, assumptions are the same for the entire planning period.

- Sierra's next general rate increase/decrease will go into effect January 1, 2023.
- Nevada Power's next general rate increase/decrease will go into effect January 1, 2024.
- Inflation rate assumed over the forecast horizon was 2 percent.
- The AFUDC rate for new projects is set at the marginal cost of capital 7.14 percent for Nevada Power and 6.75 percent for Sierra.
- For Nevada Power, the weighted average cost of capital of 7.14 percent was used as the discount rate, and was based on the currently authorized 9.40 percent return on equity ("ROE"). For Sierra, the weighted average cost of capital of 6.75 percent was used as the discount rate, and was based on the currently authorized 9.50 percent ROE.
- The assumed marginal cost of new long-term debt ranges between 2.95 percent and 4.27 percent based on current pricing information.
- A 21 percent statutory income tax rate.
- Full recovery of all above-the-line costs incurred (including energy, operating and capital).
- The CER model assumes, for each of the retired coal-fired generating units, the continued depreciation of plant balances based on the pre-existing retirement dates of each unit. This assumption essentially reflects the amortization of a regulatory asset in the amount of the unamortized balance on the retirement date using the pre-existing depreciation schedule.

G. Financial Risks

This section discusses in more detail several financial matters which are important in assessing the Companies' Preferred and Alternate Plans.

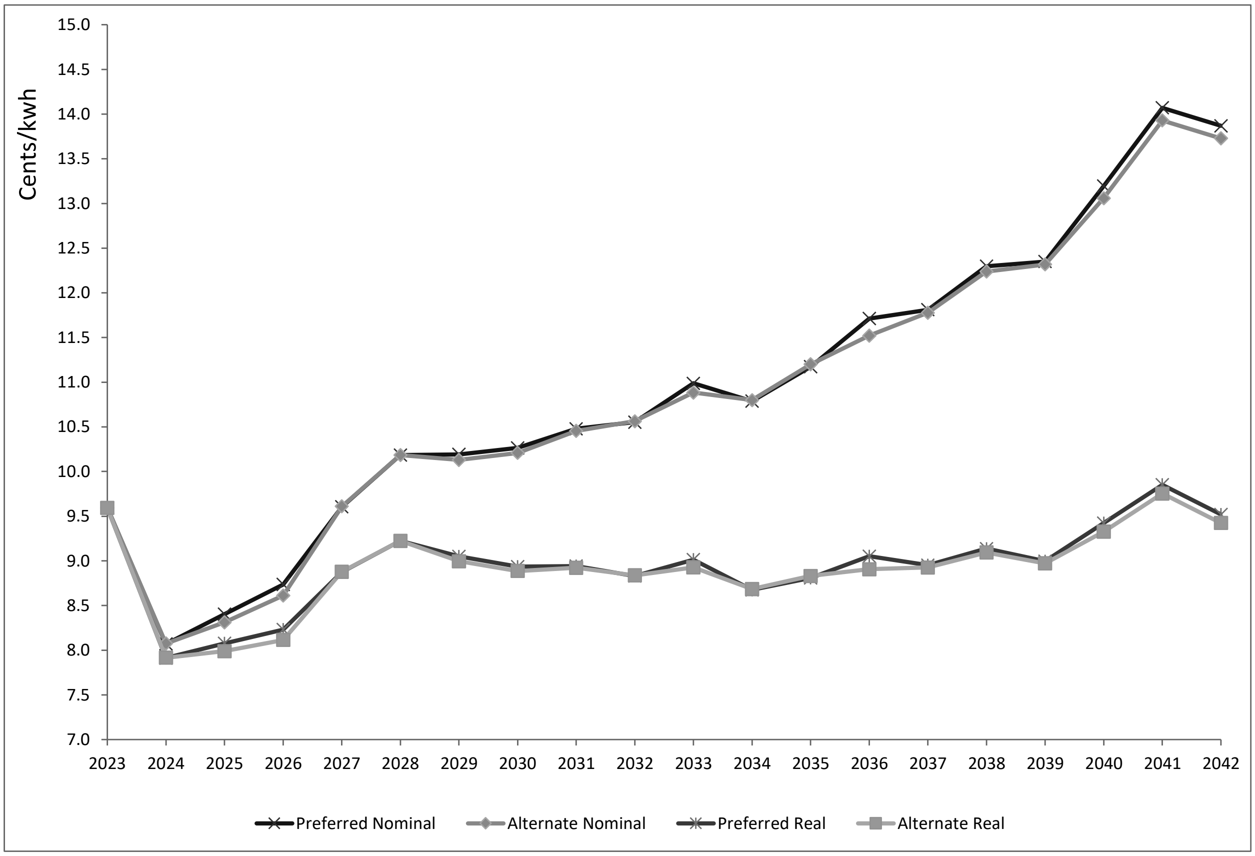
1. External Financing Costs

Due to the ongoing need to access external capital, the Companies must continue to rely on access to the financial markets. Increasing volatility in, and over-reliance on, financial markets could lead to excessive financing costs for customers in order to fund future investments on their behalf.

2. Impact on Average System Cost

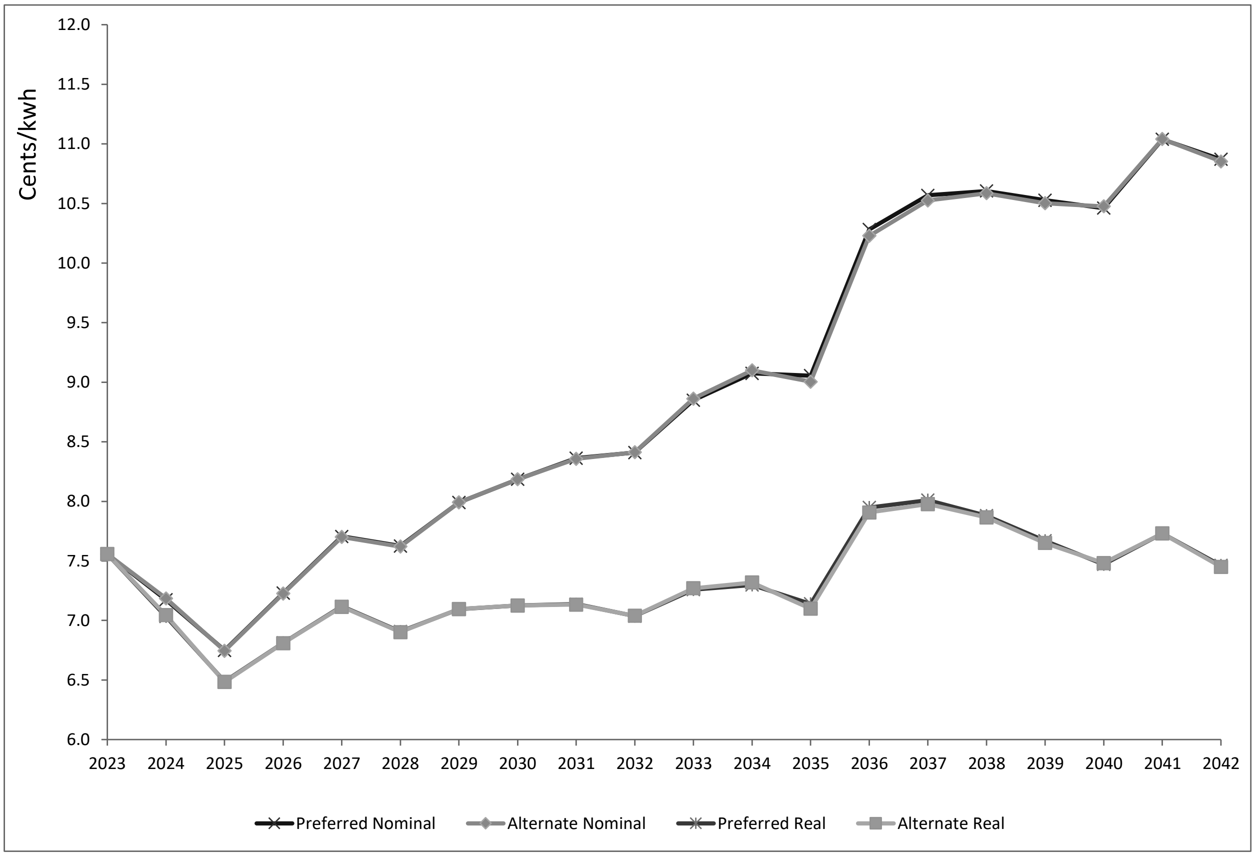
As shown in Figure FP-9, the nominal average system cost per kWh for Nevada Power under the Preferred Plan increases from 9.59 cents in 2023 to 13.87 cents in 2042, and increases from 9.59 cents in 2023 to 13.73 cents in 2042 under the Alternate Plan. The compound annual growth rate for the nominal average system cost over the forecast period is 1.9 percent for the Preferred Plan and 1.8 percent for the Alternate Plan. Average system costs are projected to increase over the next 20 years on a nominal basis, but, when inflation is reflected, then the average system costs are forecasted to decrease slightly on a real basis. The compound annual growth rates for real average system costs are (0.1) percent for the Preferred Plan and (0.0) percent for the Alternate Plan.

FIGURE FP-9
NEVADA POWER
NOMINAL & REAL AVERAGE SYSTEM COST (CENTS/KWH)



For Sierra, Figure FP-10 illustrates that the nominal average system cost per kWh is projected to increase over the 20 years from 7.56 cents in 2023 to 10.87 cents in 2042 under the Preferred Plan, and from 7.56 cents to 10.85 cents under the Alternate Plan. The compound annual growth rate for the nominal average system cost over the forecast period is 1.8 percent for the Preferred and Alternate Plans. The real average system costs for Sierra have a compound annual growth rate of (0.1) percent for the Preferred and Alternate Plans.

FIGURE FP-10
SIERRA
NOMINAL & REAL AVERAGE SYSTEM COST (CENTS/KWH)



3. <u>Credit Quality</u>

The Companies' secured debt is rated investment grade by Moody's Investor Service and Standard & Poor's Global Ratings. The Companies have maintained adequate liquidity and demonstrated the ability to successfully access the debt markets at low rates. Annual projected credit metrics for Nevada Power are shown in Figures FP-11 through FP-14 and Sierra's are illustrated in Figures FP-15 through FP-18.

Figures FP-14 and FP-18 summarize the cash generated from operations relative to capital expenditures for Nevada Power and Sierra, respectively. For the Companies, cash generated from operations exceeds capital expenditures for most of the annual periods in the Preferred and Alternate Plans. Despite the ability to fund capital expenditures with internally generated cash, Figures FP-3 and FP-4 clearly illustrate the Companies' ongoing need to access external debt capital at favorable rates in order to minimize customer rates. These external capital requirements highlight the need to maintain investment grade credit metrics. Since some of the graphs illustrate a weakening in that particular metric at times over the 20-year planning period, it is important to note that these metrics are calculated using standard methodologies which may not be the same as those used by Moody's and Standard & Poor's. The financial ratios in Figures FP-11 through FP-14 for Nevada Power and Figures FP-15 through FP-18 for Sierra show some weakening over the near term. For Nevada Power, incremental capital for the Preferred and Alternate Plans for the next five years is estimated to total $168.9 million and $282.1 million, respectively. For Sierra, the incremental capital expenditures associated with the Preferred and Alternate Plans are estimated to total $24.4 million for the Preferred and Alternate Plans over the next five years. These amounts of incremental capital are not expected to have a material negative impact on credit metrics and credit quality; however, Sierra's incremental capital will create some additional credit challenges. To the best of their abilities, the Companies will manage their capital structures in a way that mitigates any potential negative pressure on credit quality but regulatory support remains an important factor in the credit ratings process.

The Preferred and Alternate Plans include a 25 MW North Valley PPA with Ormat. NAC Chapter 704 allows the Companies to seek recovery of costs to mitigate the debt imputations performed by the rating agencies for PPAs. The Companies have historically addressed the impact of PPAs on their balance sheets and credit metrics during general rate case filings. The North Valley PPA does not represent a significant financial obligation and its debt imputation will be addressed in Sierra's general rate case filings within the broader context of Sierra's PPAs.

FIGURE FP-11
NEVADA POWER
(CONFIDENTIAL) FUNDS FROM OPERATIONS TO TOTAL DEBT (%)

[redacted]

FIGURE FP-12
NEVADA POWER
(CONFIDENTIAL) EBITDA INTEREST COVERAGE

[redacted]

FIGURE FP-13
NEVADA POWER
(CONFIDENTIAL) TOTAL DEBT TO TOTAL CAPITAL (%)

[redacted]

FIGURE FP-14
NEVADA POWER
(CONFIDENTIAL) CASH FROM OPERATIONS TO CAPEX
($ - MILLIONS)

[redacted]

FIGURE FP-15
SIERRA
(CONFIDENTIAL) FUNDS FROM OPERATIONS TO TOTAL DEBT (%)

[redacted]

FIGURE FP-16
SIERRA
(CONFIDENTIAL) EBITDA INTEREST COVERAGE

[redacted]

FIGURE FP-17
SIERRA
(CONFIDENTIAL) TOTAL DEBT TO TOTAL CAPITAL (%)

[redacted]

FIGURE FP-18
SIERRA
(CONFIDENTIAL) CASH FROM OPERATIONS TO CAPEX
($ - MILLIONS)

H. Conclusion

Given the modeling assumptions, the Companies have the capacity to finance the Preferred and Alternate Plans as modeled in the Financial Plan. The incremental capital associated with the Preferred and Alternate Plans is not significant relative to Nevada Power's and Sierra's existing capital projections. For Nevada Power, the Preferred and Alternate Plans are not expected to have a material negative impact on credit ratings or capital costs over the 2023-2042 period. Sierra's credit metrics have recently weakened and are forecasted to remain suppressed over the next five years. The incremental capital over the next five years totals $24.4 million for both Sierra's Preferred and Alternate Plans. This amount of incremental capital is not expected to materially impact Sierra's credit quality or credit ratings. This ongoing need to access external capital at attractive rates requires regulatory support and continued reliance on financial markets.

APPLICATION EXHIBIT B

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(5)(a)):

> **Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the First Amendment to the 2021 Joint Integrated Resource Plan.**

The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(5)(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 (see NAC 703.160(5)(c)):

> **Nevada Power Company and Sierra Pacific Power Company are seeking approval of the First Amendment to their 2021 Joint Integrated Resource Plan. To address supply constraints in the Western United States energy market, the Companies are seeking to modify the approved Supply Plan to add a utility-scale battery energy storage system, capacity upgrades at the existing generating facilities, and a geothermal resource via an approved power purchase agreement. In addition, the First Amendment includes a request to further evaluate and study a pumped storage hydroelectric project with an estimated capacity of 1,000 megawatts in White Pine County, Nevada.**

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.

[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.

APPLICATION EXHIBIT C

UPDATED LOADS AND RESOURCE TABLE

1	**NV Energy**																				
2	**LOADS AND RESOURCES TABLE**																				
3	*all + North Valley + 2hr BESS*																				
4		**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
5	Gross Peak	8,075	8,284	8,496	8,619	8,693	8,879	9,029	9,184	9,286	9,403	9,504	9,570	9,686	9,791	9,864	9,945	10,006	10,057	10,182	10,249
6	DSM	76	117	150	183	216	242	282	318	352	386	406	412	450	454	456	458	444	422	462	462
7	Private Generation	86	116	166	203	239	274	275	334	360	384	411	418	413	482	507	531	558	559	604	629
8	Avoided Capacity	163	173	180	193	202	218	220	235	239	251	255	257	261	271	277	277	284	285	281	267
9	Forecast System Peak	7,750	7,878	8,000	8,040	8,036	8,145	8,252	8,298	8,335	8,382	8,432	8,483	8,562	8,584	8,624	8,679	8,719	8,791	8,835	8,890
10	Sales Obligations																				
11	**NET System Peak**	7,750	7,878	8,000	8,040	8,036	8,145	8,252	8,298	8,335	8,382	8,432	8,483	8,562	8,584	8,624	8,679	8,719	8,791	8,835	8,890
12	Planning Reserves (16%)	1,240	1,261	1,280	1,286	1,286	1,303	1,320	1,328	1,334	1,341	1,349	1,357	1,370	1,373	1,380	1,389	1,395	1,407	1,414	1,422
13	**REQUIRED RESOURCES**	8,990	9,139	9,280	9,326	9,322	9,448	9,572	9,626	9,669	9,723	9,781	9,840	9,932	9,957	10,004	10,068	10,114	10,198	10,249	10,312
14	OATT Reserves	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
15	**AVAILABLE RESOURCES**	7,271	7,486	8,768	9,073	8,795	8,797	8,741	8,443	8,456	8,688	8,556	8,764	9,157	8,950	9,206	9,213	9,432	8,920	8,628	8,787
16	OPEN Position	1,719	1,653	512	253	527	651	831	1,183	1,213	1,035	1,225	1,076	775	1,007	798	855	682	1,278	1,621	1,525
17																					
18																					
19	Company	(All)																			
20																					
21	Sum of Value	Column Labels																			
22	Row Labels	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
23	existing																				
24	NVE.existing.Coal	261	261	261	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	NVE.existing.Gas	5,748	5,807	5,807	5,807	5,807	5,807	5,807	5,519	5,471	5,417	5,103	5,103	4,888	4,527	4,527	4,369	4,369	3,691	2,288	2,288
26	NVE.existing.Renewable.BESS	10	10	310	522	522	523	525	526	516	494	473	441	413	402	384	369	349	337	324	315
27	NVE.existing.Renewable.PV	11	10	93	139	141	136	134	134	128	123	119	112	106	103	100	95	95	93	92	89
28	NVE.existing.Renewable.WH	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
29	PPA.existing.Conventional	346	173	171	170	167	165	163	163	164	164	152	152	152	152	152	152	152	152	152	152
30	PPA.existing.Renewable.BESS	100	176	903	798	798	801	802	803	789	733	702	654	616	600	536	467	440	425	409	397
31	PPA.existing.Renewable.CSP	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	PPA.existing.Renewable.GEO	174	162	162	162	154	143	132	121	70	70	60	5	5	5	5	5	-	-	-	-
33	PPA.existing.Renewable.HYDRO	9	9	9	6	6	6	2	-	-	-	-	-	-	-	-	-	-	-	-	-
34	PPA.existing.Renewable.LFG	9	9	9	9	9	9	9	9	9	9	9	-	-	-	-	-	-	-	-	-
35	PPA.existing.Renewable.PV	618	632	740	615	608	585	581	581	561	532	514	485	455	442	410	381	343	336	326	325
36	PPA.existing.Renewable.WIND	20	20	20	20	20	20	20	20	20	20	20	-	-	-	-	-	-	-	-	-
37	existing Total	7,361	7,324	8,540	8,564	8,287	8,250	8,180	7,881	7,733	7,567	7,157	6,957	6,640	6,236	6,119	5,843	5,753	5,039	3,596	3,566
38	placeholder																				
39	NVE.placeholder.future	-	-	-	-	-	-	-	-	-	-	-	-	348	348	348	348	348	348	1,248	1,248
40	NVE.placeholder.renewable.BESS	-	-	-	244	244	245	245	246	367	713	948	1,256	1,571	1,742	2,063	2,299	2,545	2,716	2,926	3,086
41	NVE.placeholder.renewable.PV	-	-	-	62	62	99	112	112	156	216	259	315	372	402	460	513	584	619	665	698
42	PPA.placeholder.renewable.WIND	-	-	-	-	-	-	-	-	-	-	29	85	85	85	85	85	85	85	85	85
43	placeholder Total	-	-	-	306	306	344	357	358	523	929	1,236	1,656	2,376	2,577	2,956	3,245	3,562	3,768	4,924	5,117
44	Proposed																				
45	NVE.Proposed.Gas																				
46	1-Sun Peak wet compress_23	-	21	21	21	21	21	21	21	21	21	-	-	-	-	-	-	-	-	-	-
47	1-Lenzie 1 Peak Firing_24	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
48	1-Lenzie 2 Peak Firing_24	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
49	1-HA Peak Firing_24	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
50	1-Tracy Peak Firing_24	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
51	1-Lenzie 1 Cold Storage_24	-	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
52	1-Lenzie 2 Cold Storage_24	-	-	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
53	NVE.Proposed.Gas Total	-	21	87	87	87	87	87	87	87	87	66	66	66	66	66	66	66	66	66	66
54	NVE.Proposed.renewable.BESS																				
55	220 MW RG BESS - 2 hr_23	-	220	220	195	194	195	196	196	192	184	176	164	154	150	144	138	130	126	121	117
56	NVE.Proposed.renewable.BESS Total	-	220	220	195	194	195	196	196	192	184	176	164	154	150	144	138	130	126	121	117
57	NVE.Proposed.renewable.GEO																				
58	25 MW North Valley GEO_23	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
59	NVE.Proposed.renewable.GEO Total	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
60	Proposed Total	-	252	318	293	292	293	294	294	290	282	253	241	231	227	221	215	207	203	198	194

JOHN P. MCGINLEY

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03____

Prepared Direct Testimony of

John (Jack) P. McGinley

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

A. My name is John (Jack) P. McGinley. 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 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 have been employed by the Companies since May 1984. I have held many positions primarily focused on matters related to resource planning, renewable energy, rates, and other regulatory matters. I hold a Bachelor of Science in Mechanical Engineering from the University of Nevada, Reno. My statement of qualifications is attached as **Exhibit McGinley-Direct-1**.

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

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

A. Yes. I have testified before this Commission many times during my 38 years at the Companies related to Integrated Resource Plans ("IRP"), Energy Supply Plans ("ESP"), General Rate Cases, and many other of the Companies' filings. Most recently, I provided testimony in the 2021 Joint IRP (Docket No. 21-06001) and the Incremental Pricing tariff (Docket Nos. 21-09031 and 21-09032).

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY AND HOW IS YOUR TESTIMONY ORGANIZED?

A. The purpose of my testimony is to provide support for the Companies' First Amendment to the 2021 Joint IRP 2022-2041 ("Amendment") and introduce other witnesses for the Companies that are responsible for the many areas of the Amendment. More specifically, I support the Companies' Preferred Plan, the "All Generator Upgrades + North Valley + 2-Hr BESS" Plan, as described in Sections 2 and 8, and the Application's prayer for relief.

5. Q. ARE YOU SPONSORING ANY SECTIONS OF THE NARRATIVE, EXHIBITS OR APPENDICES?

A. Yes. I am sponsoring Sections 1 and 2 of the Amendment attached to the First Amendment Application ("Application"), as well as **Exhibit McGinley-Direct-1.** This Amendment seeks approval of a new fuel and purchase power price forecast, to amend the Generation plan with the addition of 66 megawatts ("MW") of upgrades to existing combustion turbines, to amend the Renewable plan to add a 220 MW grid-tied battery energy storage system ("BESS"), to fund a study of a pumped storage hydro project (currently under development by a third party), approval of a new 25 MW long-term power purchase agreement ("PPA") between Sierra and Ormat, and amend the Transmission plan to add infrastructure necessary for interconnection of the renewable projects presented.

6. Q. PLEASE DESCRIBE RECENT CHANGES SINCE THE FILING OF THE 2021 JOINT IRP THAT ARE DRIVING THIS AMENDMENT.

A. Recent IRPs have positioned the Companies to meet the state's decarbonization goals, while also addressing changes in climate, weather, and resource variability all while endeavoring to deliver stable prices to customers. However, recent events and reports contribute to ever decreasing confidence in the availability and deliverability of market capacity that historically the Companies rely on to meet load. While the 2021 Joint IRP reduced the reliance on market capacity relative to prior plans, there is concern that further reduction is required to reduce risk and ensure resource adequacy. This Amendment addresses increasing concerns regarding the availability and deliverability of market capacity and energy, adding resources that provide price stability.

Further, this Amendment addresses the importance of energy storage needed to meet the state's decarbonization energy policies. This Amendment proposes a new BESS project as presented by John Frankovich and examination of a pumped storage project as addressed by Mark Warden to diversify energy storage technologies. Energy storage, given the variable nature of the solar resource that is dominant in Nevada, will continue to play a critical role in meeting state and federal clean energy goals that require incorporating large amounts of capacity of renewable energy in the future. Specifically, energy storage allows the Companies to store excess solar energy produced in the day and use it later when the energy is most needed to serve customer load.

The Amendment presents to the Commission the recommended resources that NV Energy will need to address growing concerns about the availability and deliverability of regional market capacity and energy.

7. Q. PLEASE DESCRIBE THE PREPARATION OF THE AMENDMENT TO THE 2021 JOINT IRP.

A. The Preferred Plan uses the approved load forecast from the 2021 Joint IRP, addresses changes in both federal carbon policy and fuel and purchase power prices, meets or exceeds the renewable portfolio standard ("RPS") in every year, achieves the state's 2050 clean energy goal, and meets the 16 percent planning reserve margin for each utility. While the Preferred and Alternate Plans in the Amendment are very similar, the Companies selected the Preferred Plan as it is more cost-effective and most closely aligned with Nevada's energy policy. NV Energy respectfully requests that the Commission approve the Preferred Plan as described in Section 2 and the Application's prayer for relief and authorize NV Energy to take all necessary steps in the Action Plan period to implement the plan.

8. Q. PLEASE DESCRIBE HOW THE COMPANIES SELECTED THE PREFERRED PLAN.

A. As described in the Renewables and Generation narratives, the Companies investigated many options for incremental resources for this Amendment. Economic screening of different capacity and energy supply plans was conducted, and a Preferred Plan was selected from a final set of cases.

9. Q. PLEASE PROVIDE AN OVERVIEW OF THE ITEMS THE COMPANIES ARE SEEKING APPROVAL IN THIS AMENDMENT.

A. As described in Section 2, the Companies are making the following specific requests for approval:

1. Approval of the First Amendment to the 2021 Joint IRP base long-term fuel and purchase power price forecasts provided in Technical Appendix FPP-1 as presenting the most accurate information upon which to base the planning decisions set forth in the filing.

2. Approval of the Companies' Preferred Plan, including the resources generally described below:
   a. Approval of the Companies' request to amend their Supply-Side Action Plan to add 220 MW of 2-hour, 440 MWh, lithium-ion battery energy storage at the site of the former Reid Gardner Generating Station. Commercial operation is expected by May 31, 2023, at a cost of approximately $217 million and will be owned by Nevada Power. The price of the 2-hour battery is tied to the price of lithium through June 2022 and is, thus, subject to change up or down based on market pricing. As addressed by John Frankovich, lithium supply in the industry is constrained, and the demand for lithium has increased due in a large part by the demand for electric vehicle batteries. The increase in demand has resulted in an increased price volatility.

   b. Approval of the Companies' request to amend their Supply-Side Action Plan to allow Sierra to enter into the North Valley PPA for 25 MW (net) of geothermal generation. Commercial operation is expected in December 2022, with a 25-year term at a flat energy price stated in the narrative.

c. Approval of the Companies' request to amend their Supply Side Action Plan to expend approximately $6 million to install a peak-firing upgrade project on the Tracy Generating Station Units 8 and 9, increasing the station's total peak capacity by approximately 12 MW with an in-service date of May 2024.

d. Approval of the Companies' request to amend their Supply Side Action Plan to expend approximately $12 million to install a peak-firing upgrade project on the Chuck Lenzie Generating Station Units 1 through 4, increasing the station's total peak capacity by approximately 24 MW with an in-service date of May 2024.

e. Approval of the Companies' request to amend their Supply Side Action Plan to expend approximately $6 million to install a peak firing upgrade project on the Harry Allen Generating Station Units 5 and 6, increasing the station's total peak capacity by approximately 12 MW with an in-service date of May 2024.

f. Approval of the Companies' request to amend their Supply Side Action Plan to expend approximately $13 million to install a thermal energy storage project at the Chuck Lenzie Generating Station, increasing the station's peak capacity by approximately 18 MW with an in-service date of May 2024.

g. Approval of the Companies' request to amend their Transmission Plan to expend approximately $2.5 million to construct network upgrades needed to support the interconnection of the 220 MW 2-hour BESS at the Reid Gardner Substation.

3. Approval of $3.5 million to support the developer's continued development and perform the Companies' due diligence on a pumped storage hydro project located in White Pine County. In addition, this expenditure secures the Companies' exclusive right to acquire the project.

10. Q. PLEASE DESCRIBE HOW THE AMENDMENT IS ORGANIZED?

A. The organization and sponsors of each of the substantive portions of the Amendment are described below:

Consistency of Resource Plan with Companies' Strategic Objectives. Included in the Section 1 (Introduction) are discussions of the consistency between the Amendment, especially the Preferred Plan, and the Companies' strategic objectives. These discussions and the list of requests in Section 2 are supported by my prepared direct testimony. **Ryan Atkins**, Director of Trading, Analytics & Operations, supports discussion of emergent concerns regarding the availability and deliverability of regional market capacity and energy in his direct testimony.

Load, Fuel and Purchased Power Forecasts. The load forecast for the Amendment is identical to the load forecast that was filed and approved by the Commission in Docket No. 21-06001, the 2021 Joint IRP. Consistent with NAC § 704.923(2) and NAC § 704.9516(e), Table LF-1 in Section 3 – Load Forecast, provides a summary of the forecasted peak loads and energy consumption from 2021 through 2041. **Anita Hart,** Director of Resource Planning and Analysis, sponsors the use of load forecast as an assumption in the economic analysis.

Fuel and Purchase Power Price Forecasts. Zeljko Vukanovic, Market Fundamentals Lead, sponsors the wholesale power and natural gas price forecasts that are presented in Section 4 – Fuel and Purchase Power Price Forecasts. This section includes a comprehensive discussion of purchased power pricing, and describes and supports the long-term price forecasts for fuel and purchased power that underlie the analysis in the Amendment. **Mr. Atkins**, introduced previously, sponsors the coal price forecast.

Supply Side Resources. The Amendment addresses the Companies' Supply-Side Plan. The following elements of the Supply-Side Plan are addressed:

Conventional Generation. Section 5 – Amendments to Supply Side Plan - Generation addresses proposed changes to the Generation plan, including investments in upgrades to increase the capacity of existing generating units. This section, as well as the technical appendices supporting this narrative section, are sponsored by the prepared direct testimony of **John Lescenski,** Manager of Generation Engineering and Technical Services.

Current Renewable Portfolio, Compliance with Renewable Portfolio Plan and New Renewable Resources. Amendments to these portions of the Supply-Side Plan are found in Section 6 – Amendments to Supply Side Plan - Renewables. This

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section of the narrative is supported by technical appendices and the prepared direct testimony of the following subject matter experts:

Shane Pritchard, Director of Renewable Energy and Origination, supports the Companies' Long-Term Power Purchase Agreements and Renewable Energy Plan, including both the near-term outlook and long-term planning to meet Nevada's RPS. He also supports the Companies' request to execute a new PPA for the North Valley Geothermal facility in Washoe County, Nevada.

John Frankovich, Renewables Project Director, supports the Companies' request for the construction and acquisition of 220 MW of 2-hour, 440 MWh battery energy storage at the site of the former Reid Gardner Generating Station.

Mark Warden, Director of Renewables Sourcing, supports the Companies' request for $3.5 million to support the developer's continued development and perform the Companies' due diligence on a pumped storage hydro project located in White Pine County.

Transmission Plan. Amendment to this portion of the Supply-Side Plan is found in Section 7 – Amendments to Supply Side Plan - Transmission. This narrative, as well as the technical appendices supporting the narrative, are sponsored by the prepared direct testimony of **Charles Pottey**, Director of Transmission and Distribution Planning.

Economic Analysis. The Economic Analysis narrative follows the Supply-Side amendment narrative and discusses the methodologies and analytical tools used to

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perform the integrated economic analysis that underlies the Companies' selection of the Preferred Plan and Alternate Plan. This section also describes the calculation of environmental externalities for the Preferred and Alternate Plans. The Economic Analysis narrative, as well as the technical appendices supporting the narrative, are sponsored in the prepared direct testimony of **Ms. Hart**, introduced previously, and Dr. **David Harrison, Jr.**, economist and Managing Director at NERA Economic Consulting. Dr. Harrison sponsors the discussion and analysis of environmental externalities contained in the Economic Analysis discussion, as well as Technical Appendix item ECON-9.

Financial Plan. The Amendment narrative closes with a discussion of the Financial Plan. This section of the narrative discusses the methodologies and analytical tools used to evaluate the impact of the Preferred and Alternate Plans on the Companies' financial metrics. **Kimberly Hopps**, Assistant Treasurer, sponsors the financial narrative of the Amendment.

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

A. No.

12. Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I recommend that the Commission approve the Amendment including the resources described above, in the Application's prayer for relief and in the filing. The long-term obligations incorporated here address concerns regarding the availability and deliverability of market capacity and energy and, in so doing, enhance reliability, reduce risk, improve price stability through fixed pricing, increase the diversity of the Companies' supply-side portfolio and meet the state's goals and policies.

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

A. Yes.

QUALIFICATIONS OF WITNESS
JOHN (JACK) P. MCGINLEY
SIERRA PACIFIC POWER & NEVADA POWER COMPANIES D/B/A NV ENERGY
6100 Neil Road
Reno, Nevada 89511-1137

My name is John ("Jack") P. McGinley. I am the Vice President, Regulatory for Sierra Pacific Power Company and Nevada Power Company.

I graduated from the University of Nevada Reno in 1984 with a Bachelor of Science in Mechanical Engineering. Upon graduating from the University of Nevada, I have been employed full time by the Company for 38 years.

I have held various technical and leadership positions primarily in Resource Planning, Power Contracts, Regulatory, Renewables and Legislative Strategy. I have participated in and managed the preparation of many regulatory proceedings before the Public Utilities Commission of Nevada. I have provided testimony in numerous regulatory filings before the Commission.

In the early 1990's, I was responsible for the Company's Resource Planning, Research and Development and Demonstration ("RD&D") and Supply Engineering departments. In this position, I was responsible for the Company's RD&D program planning, management, and technical review and evaluation of potential supply side options including conventional generation, renewable generation including private generation solar, storage technologies and electric vehicles.

In 1998, I assumed the duties of Manager of New Product Development. This led to working with a team of individuals to establish two subsidiary companies; E-three and Simple Choice where I held the position of General Manager of Simple Choice. In 2000, I assumed the duties of Principal Consultant in the Strategic Planning Department. In 2001, I assumed the position of Principal Consultant in the Rates and Regulatory Department and was responsible for filing fuel and purchase power rider cases. Later in 2001, I assumed the duties of Manager of Long Term Resource Analysis and in 2005 I assumed the position of Regulatory Strategist. In 2007, I assumed the position of Development Director in the Renewable Energy department where my responsibilities included the formation of the department and development of renewable energy projects. In 2013, I was assigned as the project manager to lead a team of internal technical experts with the responsibility to evaluate the participation in the California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM"). The Company ultimately decided to join the EIM and received approval from the Commission in 2014. The Company went live in December 2015, with 2016 as the first full year of participation. In 2019, I assumed my current role as the Vice President of Regulatory.

In 2009, I served on the University of Nevada Chemical Engineering Advisory Board. From 2013 to 2016 I served on the Governor's Workforce Investment Board on the Clean Energy Sector Council. For many years I served as a member of the Governor's New Energy Industry Task Force and in 2016 I was appointed to the New Energy Industry Task Force Technical Advisory Committee on Distributed Generation and Storage.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JOHN McGINLEY, 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: March 18, 2022

JOHN McGINLEY

RYAN ATKINS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)
Docket No. 22-03___

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 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 14 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.**

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

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

A. In my role as Director, 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 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 including in Docket Nos. 21-04036 and 21-06001, the Companies' Second Additional Joint Energy Supply Plan Update and the 2021 Joint Integrated Resource Plan ("IRP") and Energy Supply Plan filings, respectively.

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

A. I sponsor the justification related to market capacity concerns for the Companies' First Amendment to their 2021 joint integrated resource plan ("Amendment"). This is being made in response to the evolving Western energy market including emergent concerns regarding the uncertain availability of regional market capacity. I also sponsor Sierra's coal price forecast.

6. Q. WHAT ARE THE COMPANIES REQUESTING TO RESPOND TO THE UNCERTAINTY IN THE WESTERN ENERGY MARKET?

A. In the Amendment, the Companies are seeking approval of generating assets to provide the Companies additional internal capacity. Specifically, the Companies request to amend the Generation Plan with the addition of 66 megawatts ("MW") of upgrades to existing combustion turbines, to amend the Renewable Plan to add a 220 MW grid-tied battery energy storage system ("BESS") and a new 25 MW long-term power purchase agreement ("PPA") between Sierra and the developer of a geothermal generating facility.

7. Q. WHAT MARKET CONCERNS HAVE EMERGED IN THE SUMMERS OF 2020 AND 2021?

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, over the past two summers, 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 of 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 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, increased market prices and significant supply curtailments in each of the last two summers. All of this points to added risk in relying on market purchases to cover the Companies' open positions.

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

A. Yes. The Companies experienced two major supply curtailment events over the past two summers. 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.

9. Q. ARE THE CONCERNS FROM THE SUMMERS OF 2020 AND 2021 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. In addition, many regional fossil and other baseload power plant retirements are scheduled in the near term. The Western Electricity Coordinating Council's ("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 Northwest between now and the end of 2025. These changes will dramatically affect the resource mix in the region. These concerns are compounded by the rule changes already implemented or being discussed by CAISO.

10. Q. WILL CAISO RULE CHANGES INCREASE MARKET RISK GOING FORWARD?

A. Yes. Following the events of August 2020, the CAISO pursued several market enhancements for summer 2021 and beyond. This started with a change in export priorities that impacted day-ahead export schedules. The change allows the CAISO market to adjust day-ahead export schedules to zero and exporters are not informed whether the energy will flow until approximately 55 minutes before the start of the flow hour. For counterparties utilizing day-ahead market purchases, this adds a great deal of uncertainty and risk to any supply being exported from the CAISO. In addition, the CAISO implemented changes that lowered the priority of wheel-through transactions. For any schedules that flow on transmission that traverses the CAISO balancing authority, the CAISO can prioritize the use of these schedules to serve internal CAISO load. This could increase the likelihood of curtailments for transactions being wheeled from the Pacific Northwest to the Desert Southwest. The potential for increased curtailments would not only affect the Companies, but also purchases by Open Access Transmission Tariff (“OATT”) customers in Nevada, both NRS Chapter 704B and wholesale. Additional initiatives are also currently being evaluated by the CAISO that focus on changes to the resource sufficiency evaluations (“RSE”) as a part of the Western Energy Imbalance Market (“EIM”). A number of these changes could make it more difficult for entities to pass the RSE thus limiting their ability to utilize supply that has been offered into the market. This can have significant reliability impacts as

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

an entity which is on the verge of a reliability situation could lose access to supply even if other entities have voluntarily bid the supply into the market. All these changes have led to greater uncertainty in the market as counterparties cannot be certain as to what rules may or may not be in place by the time transactions are actually due to be scheduled.

11. Q. WILL THE GENERATING RESOURCES THE COMPANIES ARE REQUESTING HELP MITIGATE THE ISSUES DESCRIBED ABOVE?

A. Yes. Adding in-system generating resources will reduce the Companies' open position and thus its reliance on market capacity purchases. This would help mitigate uncertainty surrounding climate change, wildfires, western resource retirements, and the impact of CAISO rule changes. As seen over the last two summers, events in the West resulted in significant supply curtailments for the Companies. In-system generating resources would not be subject to curtailment and could continue providing energy to Nevada customers even when issues such as regional heat waves and wildfires occur.

12. Q. PLEASE EXPLAIN WHY THE COAL PRICE FORECAST WAS UPDATED.

A. The coal price forecast, provided in the Fuel and Purchased Power Price Forecasts in Section 4 of this Amendment, was updated due to higher observed market quotes used in the short-term forecast and an updated market forecast from S&P Global Market Intelligence.

13. 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
Director, Trading Analytics and Operations, February 2021 – Current
- Responsible for directing the development and execution of strategies aimed at maximizing the value of the Companies' portfolio of energy supply resources.

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.
- Managed greenhouse gas compliance obligations.

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

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: March 18, 2022

Ryan Atkins
RYAN ATKINS

JOHN FRANKOVICH

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

First Amendment to the
2021 Joint Triennial Integrated Resource Plan (2022-2041)

Docket No. 22-03___

Prepared Direct Testimony of

John Frankovich

I. INTRODUCTION

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

A. My name is John Frankovich. I am a Renewables Project Director 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's Degree in Mechanical Engineering. I have been working in the Renewables department for 8 years growing the application of technologies and projects in NV Energy's pursuit to increase the share of renewables as resources to meet portfolio, capacity, and customer needs. In this pursuit, I have been involved in NV Energy's acquisition of energy storage through power purchase agreements in addition to the acquisition or development of projects, contract negotiations, and construction of solar and storage projects including Chukar storage (10 megawatt ("MW") storage), the Dry Lake's solar plus storage (100 MW storage), and the Build Transfer Agreements for Iron Point and Hot Pot (480 MW of total storage). More details regarding my professional background and experience are set forth in **Exhibit Frankovich-Direct-1**.

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

A. Yes, I most recently provided testimony in the Fourth Amendment to 2018 Joint Integrated Resource Plan, Docket No. 20-07023.

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

A. I sponsor the Companies' addition of a new grid-tied battery energy storage system ("BESS") at the former location of the Reid Gardner Generating Station.

5. Q. WHAT EXHIBITS ARE ATTACHED TO YOUR TESTIMONY?

A. I have attached the following exhibits to my testimony:

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

6. Q. WHAT MATERIALS ARE YOU SPONSORING?

A. I sponsor the following Technical Appendices:

- REN-6- Reid Gardner BESS Cost Estimate (Confidential)
- REN-7 Cost Analysis of BESS Addition at Fort Churchill Solar (Confidential)
- REN-8 Summary of Grid-Tied BESS Candidate Sites (Confidential)
- REN-9 Comparison of Reid Gardner BESS to Gas-Fired Acquisition (Confidential)

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

A. Yes. Technical Appendix REN-6 and Technical Appendix REN-7 contain the BESS manufacturer's costs public disclosure of which could negatively impact the Companies' ability to obtain competitive pricing from vendors in the future. The emerging market with dynamic prices for energy storage is highly competitive and not mature where all technologies are directly comparable. Disclosure of the exact construction cost breakdown may provide a false threshold for market competitiveness because there are other terms that contribute to the analysis of the value of the overall project, such as commodity cost curves, overbuild, efficiency, augmentation strategies, service agreements, and warranties. Technical Appendix REN-8 contains the Companies' assessment of candidate projects sites not selected and contains developer information, including costs, shared under a protective agreement. Technical Appendix REN-9 contains a screening-level cost comparison of the 2-hour BESS and a combined-cycle facility. This comparison was completed after the Companies' due diligence efforts for a combined-cycle facility evaluated as part of the fall 2021 Open Resource Request for Proposals. The project was not selected and its costs were shared under a protective agreement. Disclosure of confidential cost and bid information contained in Technical Appendices REN-8 and REN-9 could negatively impact the Companies' ability to obtain competitive offers from bidders in the future.

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

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

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

II. GRID-TIED BATTERY ENERGY STORAGE SYSTEM

10. Q. **PLEASE DESCRIBE THE PURPOSE AND SITING OF THE PROPOSED NEW GRID-TIED BESS PROJECT.**

A. The Reid Gardner BESS project is a 220 megawatt ("MW")/440 megawatt-hour ("MWh") lithium-ion storage system. It is proposed to help close Nevada Power's capacity open position by providing peaking capacity to support the Companies' summer needs in 2023 and beyond. It will be located on the site of the former Reid Gardner coal generating facility and has an expected commercial operation date ("COD") of May 31, 2023. **Table Frankovich-Direct-1** provides a summary of the Reid Gardner BESS project.

TABLE FRANKOVICH-DIRECT-1
BESS INFORMATION

Project	Technology	Capacity	Energy	Expected Commercial Operation	Price Estimate
Reid Gardner BESS	Lithium-Iron-Phosphate	220 MW	440 MWh	May 31, 2023	$217.1M

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

11. Q. WHY ARE THE COMPANIES PROPOSING A BESS PROJECT AT THE REID GARDNER SITE?

A. The Reid Gardner site was selected after careful consideration of several other potential host sites. Q&A 12 below and Technical Appendix REN-8 provide a complete list of sites and the respective costs that were estimated. The Reid Gardner site possessed many benefits including: location on land already owned by Nevada Power, available transmission capacity with minimal interconnection costs, a relatively short permitting timeline, ample space to host a large capacity and energy BESS, and advantages of a brownfield site (i.e., repurposing already disturbed land once used for coal-fired generation rather than disturbing a new greenfield site). In addition, by connecting to the transmission system at the 230 kilovolt ("kV") level, this BESS is well positioned to provide flexible capacity and other grid services year-round, especially during the critical peak summer season.

The Companies' selection of the Reid Gardner site also took into consideration the proximity to a substation for interconnection, transmission availability for charging and discharging, and no cost of land.

12. Q. DESCRIBE THE OTHER SITES INVESTIGATED.

A. The Companies reviewed sites including the Fort Churchill and Nellis Solar sites as potential locations. In the case of Fort Churchill, the Companies' analysis indicated that the costs of adding storage to an existing solar facility outweighed the Investment Tax Credit a co-located BESS would receive, making it less financially attractive compared to a grid-tied BESS.[1] Furthermore, this site could only host a relatively small BESS, not larger than the interconnection capacity of approximately 19 MW, which would not make a very substantial impact on the

[1] *See* Technical Appendix REN-7 for an estimate of BESS addition to Fort Churchill Solar.

capacity open position. Nellis Solar is also limited in its ability to host a BESS of substantial capacity and had other challenges making it a less attractive host site. Specifically, the Companies would need to undergo land negotiations with the U.S. Air Force to add storage at the site, the site has layout complications with respect to interconnection points, and interconnection costs were higher due to it being a distribution-connected site that required multiple circuits and metering.

The Companies also looked at three grid-tied BESS sites available from a developer. These sites were partially developed with executed interconnection agreements, site control and with permitting at various stages. These sites were not ultimately selected as they were smaller and more expensive than siting a BESS at Reid Gardner. The relative additional expense is mainly attributed to the acquisition cost for the project sites, which included land purchase and developer premiums. More detail on these sites can be found in confidential Technical Appendix REN-8.

13. Q. DESCRIBE THE REID GARDNER BESS PROJECT.

A. The Reid Gardner BESS is a 220 MW by 2-hour facility based on lithium-iron-phosphate ("LFP") chemistry and will occupy approximately four acres of the former coal-fired generating station site. It will consist of 124 containerized "MegaPacks," each approximately 2.4 MW in nominal capacity and each with its own direct current ("DC") to alternating current ("AC") set of inverters. Two MegaPacks will be connected to a medium voltage transformer that steps voltage up to an intermediate 34.5 kV for the collection circuits. The collection circuits connect to a project substation with a single generation step-up transformer that raises the voltage to 230 kV for connection into the existing Reid Gardner 230 kV Substation. The Reid Gardner BESS will be charged from the transmission system.

The BESS is air-cooled and engineered such that it does not consume water for cooling. This system, supplied and installed by Tesla, is the evolution of Tesla's product development at a cell level, product progression from power packs to MegaPacks. Reid Gardner will be the second generation MegaPack[2]. The Reid Gardner design and Tesla product will incorporate the lessons learned from previous product generations with respect to equipment monitoring and automated equipment protective features, including revised equipment layout, enhanced fault detection, battery derates, and battery isolation measures that provide improved passive fire prevention and equipment protection.

Reid Gardner BESS's 2-hour configuration is aimed at serving a narrow "net load" period. Though it is a novel configuration in the Companies' portfolio, it does not constitute a new design. From a design perspective, this two-hour BESS differs from a four-hour BESS with the same energy storage capacity, 440 MWh for this project, merely in the greater amount of AC hardware required to deliver the energy more quickly, such as inverters and transformers. It is noteworthy that a two-hour BESS can, should the need arise, still be flexibly operated at a lower capacity to deliver its stored energy over any duration more than two hours. This is important to meet the variable needs of the system throughout a day or season to season to best serve system needs.

14. Q. PLEASE DESCRIBE WHY A TWO-HOUR DURATION IS PROPOSED FOR THE REID GARDNER BESS

A. Both the two-hour and four-hour 440 MWh battery options were evaluated in Screening Analysis 3 in the Economic Analysis section of the Amendment. The

[2] Chukar is a 10 MW project commissioned by NV Energy in 2021. Chukar utilized a MegaPack 1. Reid Gardner will utilize MegaPack 2XL product. "XL" refers to "extra large".

two-hour system resulted in the lowest Present Worth of Revenue Requirement as shown in Figure EA-7 in Section 8 of the Amendment. The two-hour configuration targets a narrow capacity need. In the later evening hours of summer (i.e., hours 1900 through 2100), output from the available renewable resources declines at a faster rate than the load. The traditional peak load hours will be supplied partially by solar and the remaining peak load – the "net peak," or load less dispatch-limited resources – is a shorter duration peak. This creates a resource gap to be filled to replace the lost solar generation for a short duration of the highest need. The two-hour configuration is a tailored solution as it can deliver all of its stored energy within the timeframe of the greatest "net peak" need. In contrast to a two-hour BESS, the four-hour BESS, with same amount of energy storage but half the capacity, would only be able to deliver half of its energy in the same two-hour window of time. The two-hour BESS suits a sort of "super-peak" need whereas four-hour BESS and longer duration energy storage are better suited to serve broader peak energy needs. During the "super-peak", a four-hour BESS would support only half the resource adequacy need and discharge only half of its energy. The proposed two-hour BESS is flexible enough that it can be discharged over longer periods at lower power rates whereas the four-hour BESS cannot discharge at higher rates for shorter durations.

The proposed BESS with a two-hour duration is a flexible resource that supports a resource adequacy need, for a short duration. Since the Reid Gardner BESS project is proposed to fill a short duration capacity need, proposing the BESS system with a shorter duration results in a lower cost per unit of capacity. **Table Frankovich-Direct-2** shows that the two-hour BESS system Capacity Cost represents only 57 percent of the Capacity Cost of a four-hour system with the same energy rating at Reid Gardner.

TABLE FRANKOVICH-DIRECT-2

REID GARDNER BESS TWO-HOUR VERSUS FOUR-HOUR COMPARISON

BESS Project	Capacity	Energy	Capacity Cost $ per kW	Energy Cost $ per kWh
Reid Gardner two-hour	220 MW	440 MWh	$ 987	$ 493
Reid Gardner four-hour	110 MW	440 MWh	$ 1,745	$ 436

15. Q. HOW DOES THE PRICE OF THE PROPOSED REID GARDNER BESS COMPARE TO THE THREE BESS PROJECTS PROPOSED IN DOCKET NO. 21-06001?

A. As shown below in **Table Frankovich-Direct-3**, the Reid Gardner BESS is less expensive on a dollar-per-kilowatt capacity basis but more expensive on a dollar-per-kilowatt-hour ("kWh") energy basis than the three projects filed in the Docket No. 21-06001, the 2021 Joint IRP. The comparison in **Table Frankovich-Direct-3** below shows, on a capacity cost basis, the Reid Gardner BESS system is 36 percent less than the four-hour systems costs previously proposed. This is a benefit of a two-hour system. However, the reduced capacity cost in turn means that the energy basis is more expensive. This is always the case with two-hour systems versus four-hour systems since twice as many transformers and inverters are installed in a two-hour system compared to an energy-equivalent four-hour system. Since the Reid Gardner project is proposed to fill a short duration capacity need, a capacity cost comparison is the appropriate unit cost to compare.

TABLE FRANKOVICH-DIRECT-3

COMPARISON OF REID GARDNER BESS TO BESS PROPOSED PROJECTS IN 2021 JOINT IRP

BESS Project	Capacity	Energy	Capacity Cost $ per kW	Energy Cost $ per kWh
Reid Gardner	220 MW	440 MWh	$ 987	$ 493
Chukar 2, Brunswick & Steamboat	66 MW	264 MWh	$ 1,530	$ 382

16. Q. EXPLAIN HOW THE CONSTRUCTION COST OF REID GARDNER BESS COMPARES TO OTHER CAPACITY OPTIONS?

The Reid Gardner BESS compares favorably to other capacity projects proposed in this First Amendment to the 2021 Joint IRP, and projects previously proposed and approved in the 2021 Joint IRP as shown in Narrative Table REN-5. At a screening level for Capacity Cost ($ per kilowatt ("kW")), the project also compared favorably to a combined cycle project that was received in the fall 2021 Open Resource request for proposals. That screening-level comparison is shown in confidential Technical Appendix REN-9. The final recommendation to include the Reid Gardner BESS as part of the Preferred Plan is supported by the economic analysis described in Section 8, Economic Analysis and sponsored by Anita Hart.

17. Q. HOW WAS THE COST DEVELOPED FOR THE REID GARDNER PROJECT?

The proposed cost is based largely on the negotiated cost and scope for Tesla equipment and for Tesla as the Engineer, Procure, and Construct ("EPC") contractor. As of the time of this filing, the Tesla negotiations will be substantially complete with costs set with a Lithium index price adjustment and production capacity reserved. Other costs include owner's engineer costs, permitting costs, project management costs, and the interconnection costs. Negotiations with Tesla were ongoing as of the date of this filing to finish the detailed scope, schedule, and contract price adjustment for Lithium index pricing. Due to the price volatility of the Lithium Carbonate used in the battery system, the EPC contract will include an index adjustment method from a baseline. The recent volatility of this commodity price has resulted in an industry practice that utilizes contracts with index-based price adjustments that adjust up or down. Lithium supply in the industry is constrained, and demand increases, in a large part driven by demand for electric vehicle batteries, have recently created volatility. Index adjustments have become a new commercial tool in contracting to address the volatility with commodities in today's supply chain. Suppliers have become resistant to contract fixed costs without index adjustments to cover price changes that cannot be controlled. This has fundamentally shifted the contracting from lump sum, fixed cost contracts to contracts with index adjustments when a commodity or commodities cannot be forecasted or controlled. Tesla negotiations are targeted to be completed by the end of March.

The index adjustment will be based on an average index price for an evaluation quarter which will be the full quarter ending at least 180 days prior to the final delivery of the MegaPacks. The baseline index price, upon which the $217 million estimate is based, was established in November 2021. Since November, the index has increased. Using the March 3, 2022, spot price for the Lithium Carbonate index would result in a BESS equipment cost increase of $17.5 million, or $80/kW added to the Capacity Cost shown in **Tables Frankovich-Direct-2** and **Frankovich-Direct-3** for Reid Gardner BESS. The EPC provides for a maximum for the index price at approximately five times the baseline index price of Lithium Carbonate, or approximately $50 million (which includes the current currency rate adjustment). If the maximum is reached this will trigger a 30-day period to negotiate an agreement. If an agreement between the parties is not reached, the Companies will have a termination payment of 10 percent of the Tesla battery value plus direct EPC costs. In exchange the Companies would receive batteries equal to 10 percent of the adjusted value of the Tesla batteries as shown in REN-6 - Reid Gardner BESS Cost Estimate (Confidential). The converse also applies: should the Lithium Carbonate index pricing be lower than the baseline, a negative adjustment would be applied to the equipment pricing.

18. Q. WHAT IS THE STATUS OF THE UTILITY ENVIRONMENTAL PROTECTION ACT (UEPA) PERMIT FROM THE COMMISSION FOR THE REID GARDNER STORAGE PROJECT?

A. Since the project includes 230 kV equipment associated with the battery storage project, including the 230 kV breaker addition at Reid Gardner Substation, a 230 kV transmission line, and the project's 230 kV substation, a UEPA permit to construct is required. Due to the short development timeline, Nevada Power intends to file the UEPA application for a Permit to Construct either concurrently with, or shortly after, this filing. Similar to projects filed in Docket No. 19-05003, Nevada Power will request the Commission conditionally approve the UEPA application on the Commission's approval of the Reid Gardner BESS in this filing.

19. Q. WHAT IS THE STATUS OF THE INTERCONNECTION?

A. The project's application for an interconnection was accepted on January 28, 2022. Subsequently, Nevada Power requested provisional status and a BESS charging study. The Designated Network Resource study was requested on January 31, 2022. The study results are expected in April 2022. Network upgrades are expected to be of minimal scope for the direct interconnection. The Reid Gardner project cost includes the expected interconnection cost responsibility. More details on the interconnection status are found in the direct testimony of Charles Pottey and in the Transmission plan narrative.

20. Q. ARE THERE RISKS TO THE SCHEDULE TO DELIVER THE REID GARDNER SITE BY MAY 31, 2023?

A. Yes. The Companies have focused on bringing storage projects forward to meet the May 2023 COD in order to be better positioned from a capacity and energy perspective ahead of the summer peak period. The screening activities and pre-development activities were focused on sites and mitigations to support filing for a project approval with as much certainty as possible. The Reid Gardner site selection was a result of considerations described above that help mitigate schedule risk items such as land control, permitting, and site interconnection. Pre-development activities such as geotechnical study, hydrologic study, and some pre-engineering are progressing to ensure permitting timelines and procurement timelines are met. A transformer procurement was pursued to mitigate the long-lead timeline for that equipment. The extent of the permitting and known procurement timelines have been addressed in a project schedule to meet the COD. In short, the Companies have undertaken activities to mitigate the risks that are foreseeable and controllable.

But in today's world of global disruptions to supply chains and considering the extremely short duration of the execution of this project once Commission approval is obtained, it is impossible to state that a May 2023 COD is certain, though NV Energy is actively working with Tesla to achieve the May 2023 date. It is responsible to point out that other supply risks in general commodity and components in the manufacture of equipment are possible that may impact an already short duration project execution schedule.

21. Q. PLEASE SUMMARIZE THE COMPANIES' REQUESTS WITH REGARDS TO THE GRID-TIED BATTERY ENERGY STORAGE SYSTEMS.

A. The Companies request that the Commission approve Nevada Power's acquisition of the Reid Gardner grid-tied BESS project. Specifically, the Companies request approval of Nevada Power's construction of the 220 MW Reid Gardner BESS project for an estimated cost of $217.1 million, as may be adjusted according to a Lithium index price described in Q&A 17 above.

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

A. Yes, it does.

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Las Vegas, NV 89118

EDUCATION: BS - Mechanical Engineering - University of Reno – 1995

NV Energy:

2014-Present: Project Director, Renewables and Origination

Responsibilities includes the evaluation of project and technology opportunities to support strategic planning; addressing regulatory matters as required involving new renewable energy technologies, legislation and technology application; renewable development, and resource application for customer programs. Directs projects and negotiations for project acquisition, development, and construction. Also directs studies for renewable technology applications and special assignments. Ensures alignment with short and long term organizational goals and objectives. Works with the transmission and distribution departments to further renewable energy penetration initiatives, electrification of transportation and non-wires alternatives to capital projects. Works closely with top executive management to keep them apprised of strategic opportunities and threats.

2012-2014: Production Manager for Generation

Responsible for project development including scope, schedule, and budget for generation plant expansions, major capital improvements, emission improvements, and work force design. Worked closely with plant management, resource planning, environmental experts, consulting services, generation leaders and executive leaders to facilitate project development and goals. Specific projects included Best Available Retrofit Technology (BART) projects for Fort Churchill and Tracy units, Maximum Available Control Technology (MACT) projects for Valmy and Reid Gardner units, Inlet Chilling studies and project development for gas turbine fleet, plant acquisitions, and general planning support for Generation, renewable energy, and resource planning.

2006-2012:
Production Manager, Tracy Station
Operations Manager, Tracy Station
Maintenance Manager, Tracy Station

Responsible for the safe, reliable, and low cost production at the Tracy Power Station with over 1000 MW of generating capacity. Accomplishments included workforce transition and facility transition to accept a unit expansion with 500 MW Combined Cycle and unit retirements. Areas of responsibilities covered short and long term budget development and adherence, operations scheduling and execution, maintenance planning, scheduling, and execution, outage planning and execution, and compliance with NERC/WECC, environmental permits and regulations, and OSHA and other safety regulations.

1999 – 2006
Maintenance Manager, Fort Churchill Power Station
Plant Engineer, Fort Churchill Power Station

Other experience:

1997-1999: Round Mountain Gold Corporation - Plant Engineer

- Plant inspections, performance evaluations, reliability projects, production improvement projects, maintenance project planning, emergency restoration of plant operation
- Major accomplishments: defect free construction of heap leach piping, plant expansions meeting schedule and quality goals, maintenance improvement projects measurably improved annual gold production

1995-1997: Geothermal Development Associates – Mechanical Engineer

- Mechanical designer, project management for clients, conceptual plant design including thermal cycle performance, equipment sizing, and layouts for business development

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, JOHN FRANKOVICH, 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: March 18, 2022

JOHN FRANKOVICH