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 Fifth Amendment to the 2021 Joint Integrated Resource Plan.	Docket No. 23-08___

VOLUME 1 OF 6

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

TRANSMITTAL LETTER

August 21, 2023

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. 23-08___- 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 Fifth Amendment to the 2021 Joint Integrated Resource Plan.

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 a Joint Application for approval the Fifth Amendment to the 2021 Joint Integrated Resource Plan. The Fifth Amendment seeks, in part: (1) to convert the existing coal fueled plant at the North Valmy Generating Station to a cleaner natural gas fueled plant; (2) to purchase, install, and operate a company-owned 400 megawatt ("MW") solar plant along with a 400 MW, four-hour battery storage system in Northern Nevada; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW photovoltaic ("PV") and 149 MW battery energy storage system ("BESS") Crescent Valley Solar project; (5) to construct the Esmeralda and Amargosa substations transformers; and (6) to construct the necessary infrastructure in the Apex Area Master Plan. The Joint Application more comprehensively presents the requests included in the Fifth Amendment.

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

- **Application Exhibit A** is a narrative discussion of the Amendment.

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

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

- **Ryan Atkins**
- **Timothy Pollard**
- **Zeljko Vukanovic**
- **Mathew Johns**
- **John Lescenski**
- **Jimmy Daghlian**
- **Gaurav Shil**

- **Deborah Florence**
- **Charles Pottey**
- **Clyyne Cook**
- **Kimberly Williams**
- **Nicolai Schlag**
- **David Harrison**
- **Michael Behrens**
- **Kimberly Hopps**
- **Carolyn Barbash**.

Certain information set forth in the Narrative, supporting testimony 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 Argus Media ("Argus") and Wood Mackenzie Limited ("WoodMac"), fee subscription services and recognized providers and consultants for the energy industry and cannot be publicly disclosed. This information is protected by confidential provisions between the Companies and these providers 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.

Generation. Technical Appendices GEN-1 and GEN-2 are marked as confidential. Technical Appendix GEN-1 includes the Generating Unit Characteristics Table that provides characteristics used in the dispatch of the Companies' generating units. Technical Appendix GEN-2 includes the generating unit characteristic assumptions for potential new generating units that are used in the production cost modeling. Public release of this information would allow parties bidding energy to the Companies to price their units based on NV Energy's costs, which would adversely affect NV Energy's customers. Table GEN-4 of the narrative contains costs information related to Valmy coal to gas conversion. Table GEN-7 of the narrative contains costs information for Tracy Units 4 and 5 SCR project. Disclosure of this confidential information would reveal the Companies' cost expectations for equipment and installation allowing future bidders to submit less competitive offers, which will in turn result in higher costs to NV Energy's customers. Table GEN-10 of the narrative similarly reflects Valmy simple-cycle plant construction costs information. Valmy simple-cycle plant is not requested for approval in this Joint Application.

Renewables. Technical Appendices REN-3, REN-4, REN-5, REN-6 and REN-7 contain confidential information. Technical Appendices REN-3, REN-6 and REN-7 are confidential as they contain the Companies' due diligence and pricing related reviews of the Sierra Solar project and Crescent Valley asset purchase acquisition. Public disclosure of this information could provide an unfair market advantage to competitors by showing the Companies' internal analysis of projects. Confidentiality of the Companies' technical evaluation of projects is essential to future successful negotiations and competitive solicitations to obtain the best value on behalf of the Companies' customers. The references to the confidential information contained in Technical Appendix REN-6 are similarly redacted in the Renewables Section of the narrative. Technical Appendices REN-4 and REN-5 contain project pricing information that, if made public, would impair the Companies' ability to negotiate the best pricing for Sierra Solar or other similar projects in the future. Technical Appendix REN-5 provides the results of the Companies' 2023 RFP shortlisted bids received for solar-plus-storage projects. A portion of Table REN-5 of the narrative similarly displays this confidential bid information. Disclosure of confidential cost and bid information contained in Technical Appendices REN-3, REN-4, REN-5, REN-6 and REN-7 could negatively impact the Companies' ability to obtain competitive offers from bidders in the future and deliver the best value to the Companies' customers.

Economic Analysis. Technical Appendices ECON-3, ECON-4, ECON-6 and ECON-10 contain confidential information. Technical Appendix ECON-3 contains unit-specific cost data, which is market sensitive data, of each of the Companies' generators. Costs specific to each generator are commercially sensitive information. Disclosure of such information could put the Companies at a competitive disadvantage. Technical Appendix ECON-4 contains proprietary forecast price data obtained from a third party. Technical Appendices ECON-6 and ECON-10 contain sensitive projected capital cost information related to future 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's and Nevada Power's debt is publicly traded, and the information identified in the figures above has 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. The portion of Mr. Behrens's testimony presenting the Companies' credit metrics is similarly confidential.

Workpapers. Electronic files supporting this Joint Application are enclosed with this letter and will also be delivered to the Regulatory Operations Staff and the Bureau of Consumer Protection. The workpapers supporting the confidential portions of the filing listed above are identified as confidential.

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

Pursuant to NAC § 703.5274(2), the Companies hereby request that the above-described information not be disclosed to the public. The Companies request that this information remain confidential for a period of five years after which the information may be destroyed or returned. 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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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 Fifth Amendment to the 2021 Joint Integrated Resource Plan.	)))))	Docket No. 23-08___

JOINT APPLICATION TO APPROVE THE FOURTH AMENDMENT TO THE 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' Fifth 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 Friday, February 2, 2024.

I.

SUMMARY AND INTRODUCTION

This Fifth Amendment provides a complete solution to the timely retirement of coal combustion at the North Valmy Generating Station ("Valmy") and the need for voltage support and available around-the-clock generation in the Carlin Trend load pocket. In addition, it addresses capacity and renewable portfolio standard ("RPS") concerns created by incremental cancellations and delays of previously approved projects, which aggravate persistent concerns about the uncertain availability of regional market capacity and energy. The filing continues to advance the state's objectives to become a leading producer and consumer of renewable energy while supporting growth in the state.

Nevada's energy evolution remains dynamic as the West continues to experience capacity shortfalls during peak usage periods. As described in the Fourth Amendment to the 2021 Joint IRP ("Fourth Amendment"), this has resulted in significant shortfall risk throughout the West with multiple states experiencing energy emergency alerts over the last several years. Nevada is not immune and has experienced energy supply issues three years in a row. As discussed in recent IRP filings, Nevada's historic level of reliance on the energy market to meet peak period demand is no longer the most reliable and economic direction and has introduced significant risk of energy shortfalls and associated rolling blackouts in recent years. The Fifth Amendment utilizes the load forecast filed in the Third Amendment to the 2021 Joint IRP ("Third Amendment"), which indicated increased summer peak and energy demand related to both native load growth and transportation electrification. NV Energy continues to focus on reducing Nevada's exposure to uncertain market resources to meet peak demand and is working towards increased energy independence to ensure reliable service for our customers while supporting future economic and job growth in our state.

Renewable project developers, citing various photovoltaic ("PV") and battery energy storage system ("BESS") market conditions, continue to struggle to meet their contractual obligations to the Companies to deliver Commission-approved renewable projects. The Companies had to remove two more projects, the Southern Bighorn Solar PV and BESS project approved in the Third Amendment to the 2018 Joint IRP and the Chuckwalla PV/BESS project approved in the Fourth Amendment to the 2018 Joint IRP, from the resource portfolio as well as delay the commercial operation date of the Boulder Solar III PV/BESS project approved in the Fourth Amendment to the 2018 Joint IRP. These cancellations and delay are described in the Renewable Section of the narrative.

As already addressed in the Fourth IRP Amendment, Docket No. 22-11032, the previously approved Hot Pot and Iron Point PV/BESS projects are no longer under development as planned. In January of 2023, the Companies received Notices of Termination of the Build Transfer Agreements for the Iron Point and Hot Pot projects, respectively, from the project developer. In

March 2023, the Companies responded acknowledging the developer's intention to terminate the build transfer agreements and offered a formal termination agreement. Subsequently, in April 2023, the developer responded with assertion that the original notice served as valid termination, and a formal termination agreement was unnecessary. The Companies responded to the developer in June 2023 with notices of termination of the agreements for each of the projects. Therefore, at the time of this filing, each party has provided the other with notification of termination of the build transfer agreements for Iron Point and Hot Pot, and thus the projects as previously approved are no longer moving forward. Potential damages recovery discussions between the parties are ongoing and not final at this time. Moreover, the developer bid the Iron Point and Hot Pot projects into the Companies' 2023 Open Resource Request for Proposals ("RFP") as a combined Build Transfer Agreement project with updated pricing and commercial operation dates. The bid was not the most competitive with other bids in the RFP, nor was it selected as the best Valmy area solution, as described in the Transmission, Generation, and Economic Analysis Sections of the narrative to this Amendment.

The Companies diligently engaged in negotiations with the Hot Pot and Iron Point developers to bring the projects to fruition. Ultimately, the developers were unwilling to meet their contractual obligations and construct the projects on the terms contracted. As approved in Docket No. 21-06001, the Iron Point project had a commercial operation date ("COD") of December 31, 2023, with a levelized cost of energy ("LCOE") of $51.06 per megawatt-hour ("MWh").[1] The Hot Pot project had a COD of December 1, 2024, with an LCOE of $49.97 per MWh.[2] As Table REN-5 within the Supply Plan – Renewables Section of the narrative demonstrates, the developer economics for the projects changed drastically. As rebid, the developer for the combined Hot Pot/Iron Point project identified the COD of June 1, 2026, with the LCOE pricing substantially different from the LCOEs presented in Docket No. 21-06001. This Joint Application demonstrates

[1] Joint Application Vol. 14 at 189-192.
[2] *Id*. at 192-94.

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that repowering Valmy on gas represents a highly cost-effective and reasonable resource path which is superior to other options, including PV/BESS projects.

This Fifth Amendment specifically addresses a complete solution to the timely retirement of coal combustion at Valmy and the need for voltage support and available around-the-clock generation in the Carlin Trend load pocket. In the 2021 Joint IRP, the Hot Pot and Iron Point PV/BESS projects were identified as the replacement for the coal-fired Valmy plant that provided both capacity and the identified system needs, while also contributing to the RPS. With the removal of these two projects from the Loads and Resources ("L&R") tables in the Fourth Amendment and the new requirement for around-the-clock generation to provide the transmission support for the Carlin Trend load pocket,[3] the Companies are proposing a cost-effective new and complete replacement for the coal-fired Valmy plant as well as continuing the replacement for the RPS contribution expected from the Hot Pot and Iron Point projects. More information pertaining to the repowering of the existing Valmy units can be found in the Generation and Economic Analysis Sections of the narrative. In preparing this Amendment, the Companies explored various Valmy solution pathways, evaluated key considerations, and, based on that analysis, proposed the preferred Valmy coal retirement solution.

Among other requests, the Amendment chiefly seeks: (1) to convert the existing coal fueled plant at the North Valmy Generating Station to a cleaner natural gas fueled plant and continue its operation through 2049; (2) to purchase, install, and operate a company-owned 400 megawatt ("MW") Sierra Solar PV plant along with a 400 MW, four-hour battery storage system in Northern Nevada along with associated transmission infrastructure; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW PV and 149 MW BESS Crescent Valley Solar project; (5) to construct the Esmeralda and Amargosa substations transformers; and (6) to construct the necessary infrastructure in the Apex Area Master Plan.

[3] *See* Transmission Section of the narrative.

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The items above[4] constitute the Companies' Preferred Plan, also designated as the Repower Minimum Plan in the Economic Analysis Section of the narrative. The Preferred Plan in this Amendment provides a complete Valmy solution, addresses resource adequacy and RPS compliance, addresses state and federal carbon policy and changes in fuel and purchase power prices, advances the state's 2050 clean energy goal, and meets the 16 percent planning reserve margin ("PRM") for each utility. Of the alternative plans presented, the Preferred Plan reflects the lowest Present Worth of Societal Costs.

The Joint Application also requests designating Sierra Solar as a critical facility pursuant to NAC § 704.9484. The project will provide NV Energy's customers the benefits from all associated environmental and renewable energy attributes as the company-owned solar plus storage resource. It will help reduce dependency on fossil-fueled generation and the volatile wholesale market, promote diversity of supply side resources and retail price stability, and protect reliability. Sierra Solar will also contribute to the Companies' RPS compliance and achieving the state-wide goal of zero net carbon by 2050. The requested incentives include accounting treatment in the form of construction work in progress ("CWIP") balances in rate base and project expenses after the in-service date recorded in a regulatory asset with a carrying charge.

In addition, the Joint Application requests establishment of a regulatory asset to record Valmy coal to gas conversion decommissioning and remediation costs. The Companies seek to establish a regulatory asset for Valmy plant assets slated for retirement upon termination of coal-powered generation and conversion to natural gas generation. Upon completion of the decommissioning work, the Companies will seek recovery of all costs accumulated in the regulatory asset account (net book value of the assets and decommissioning/removal costs) in a future general rate case.

[4] With the exception of the Crescent Valley assets purchase request.

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
Reno, NV 89511
775-834-3470
Roman.Borisov@nvenergy.com

Aaron Schaar
Manager, Regulatory Services
6100 Neil Road
Reno, NV 89511
775-834-5823
regulatory@nvenergy.com

III.

APPLICATION EXHIBITS

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

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

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 prepared direct testimony of the following witnesses:

> **Ryan Atkins**, Vice President, Resource Optimization, provide support and overall policy for the Companies' Fifth Amendment to the 2021 Joint Integrated Resource Plan, provide support surrounding regional market efforts being undertaken by the Companies' such as participation in the Western Resource Adequacy Program ("WRAP") and the development of a future day ahead wholesale market, and provide support related to continuing concerns regarding the uncertain availability of regional market capacity and the continued challenges surrounding the availability, deliverability, and price of coal supply.

> **Timothy Pollard**, Director of Load Forecasting, supports the load forecast.

Zeljko Vukanovic, Market Fundamentals Lead, sponsors the wholesale power and natural gas price forecasts. Also, sponsors the Technical Appendix FPP-1 - Fuel and Purchased Power Price Forecasts, which is confidential.

Mathew Johns, Vice President, Environmental Services and Land Management, support the discussion of certain environmental regulatory matters in the Generation narrative as they relate to decisions for Valmy and Tracy 4/5 in this Docket.

John Lescenski, Manager, Plant Engineering and Tech, support the engineering issues related to the proposed projects to convert the Valmy coal fired generating units to operate on natural gas and continue operating the units beyond 2025 and the installation of Selective Catalytic Reduction ("SCR") on the Tracy Unit 4 and the continued operation of Tracy Units 4 and 5 beyond 2031; also support the engineering issues related to the Valmy Simple Cycle Plant included in the alternative cases.

Jimmy Daghlian, Vice President, Renewables, sponsors the Supply Plan – Renewables section of the narrative discussing the Companies' renewable projects and provides an overview the right to lease the Amargosa Valley Solar Energy Zone ("SEZ") from the Bureau of Land Management ("BLM").

Gaurav Shil, Director of Renewable Energy and Origination, sponsors the Companies' Long-Term Power Purchase Agreements and Renewable Energy Section of the Supply Plan, Section 6 of the narrative.

Deborah Florence, Director of Corporate Taxation, sponsors the analysis of tax benefits available under the new Inflation Reduction Act ("IRA") for BESS projects as presented in the Renewables section of the Supply Plan;

Charles Pottey, Director of Transmission and Distribution Planning, sponsors the Transmission Plan section of the Supply Side narrative discussing the Companies' transmission systems and associated projects; supports the Companies' requests to construct the required transmission system network upgrades required for the Preferred Plan or other alternative plans.

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Clyyne Cook, Director of Transmission and Distribution Projects, sponsors the Transmission Plan section of the narrative discussing the Companies' transmission system and associated Apex area.

Kimberly Williams, Director of Resource Planning and Analysis, sponsors the economic analysis and selection of the Preferred Plan. Together with Dr. David Harrison, supports the Environmental and Externalities results contained in Technical Appendix ECON-9.

Nicolai Schlag, Partner at Energy and Environmental Economics ("E3"), supports NV Energy's continued use of the prior Planning Reserve Margin ("PRM") and Effective Load Carrying Capability ("ELCC") analyses and evaluates NV Energy's current plans to reduce its open position.

David Harrison, Economist and Affiliated Consultant at NERA Economic Consulting, supports the environmental cost and economic impacts analysis.

Michael Behrens, Vice President, Chief Financial Officer, sponsors the Financial Plan to the Amendment.

Kimberly Hopps, Director, Financial Business Support, sponsors the financial models that make up the Financial Plan and customer rate impact analysis.

Carolyn Barbash, Vice President, Transmission Development & Policy, provides an updated cost forecast for the Greenlink Nevada transmission project and the key reasons for the project cost escalation.

To make the information contained in the filing more digestible, the Companies included a flow diagram of the economic analysis methodology. The flow diagram prefaces the economic analysis narrative and provides a detailed overview of the IRP modeling methodology. In addition, the Companies are providing a workpapers index for easier navigation and will hold a walkthrough of the filing with the participants. Additionally, in light of Commission's request in recent IRP filings, the Companies added a customer rate impact analysis subsection to the Financial Plan.

V.

CONFIDENTIALITY

Certain information set forth in the narrative, supporting testimony 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.

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VI.

REQUEST FOR DEVIATION

The Companies' Preferred Plan contains Sierra Solar BESS project. While not a part of the Preferred Plan, the Companies included the Valmy BESS project within the Alternate Plan. The Sierra Solar and Valmy BESS projects are eligible for tax credits under the new IRA. The IRA provides Investment Tax Credit ("ITC") for the battery storage projects and allows the Companies to pass through to the customer the full benefit of those credits by opting out of normalization. The Companies intend to opt out of the ITC normalization for the Sierra Solar and Valmy BESS projects. The Companies are requesting a waiver of NAC § 704.6546, use of separate-entity method by utility members of consolidated group, to take full advantage of the benefit. The Companies are submitting the deviation request pursuant to NAC § 704.0097. Specifically, NAC § 704.6546 provides:

> 1. In computing federal income taxes, utility members of a consolidated group must use a separate-entity method, rather than a consolidated-company approach which includes impacts of nonutility and affiliated operations.
> 2. As used in this section, "consolidated group" means the combination of two or more affiliated corporations or enterprises for the purposes of financial statements, income tax returns, or both, which may include utility and nonutility operations or entities

With normalization, ITC is recaptured onto the books of the company and amortized as a reduction of income tax expense over the book life of the underlying asset. There is no adjustment to rate base. Without normalization, rate base is adjusted for any amount of credits both generated and utilized by the Companies.

However, if the Companies continue to use the separate-entity method, as required by NAC § 704.6546, they will not be able to monetize the tax benefits when they are generated. Instead, they will have tax credit carryforward balances that will take years to utilize. The Companies will not be able to monetize the tax benefits immediately because each utility must generate enough taxable income on its own to absorb the tax depreciation and credits generated each year. Since the benefits are substantial, it will take several years to fully utilize all the tax benefits.

Furthermore, the unused tax credit carryforward balances will be recorded on the balance sheet as a deferred tax asset and will be included in rate base. This rate base increase will increase revenue requirement.

If granted the waiver of NAC § 704.6546, the full benefit of the ITC credits generated will reduce rate base and benefit customers through lower rates. Accordingly, the deviation from NAC § 704.6546 is for good cause and is in the public interest. The deviation would not be contrary to statute.

VII.

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 Amendment to the 2021 Joint IRP base long-term fuel and purchased 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. Valmy 1 & 2 Repower on Natural Gas

      i. Approval of the Companies' request to amend their Supply Plan to expend approximately $83 million, Sierra's share of the total project cost shared with Idaho Power Company, to repower existing coal-fired combustion to natural gas fired combustion at the Valmy Generating Station, with an in-service date of December 2025 for Valmy 1 and May 2026 for Valmy 2.

      ii. Approval of the Companies' request to amend their Supply Plan to accommodate the continued operation of the repowered Valmy Generating Station through 2049.

   b. Sierra Solar PV & BESS

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

i. Approval of the Companies' request to amend their Supply Plan to expend approximately $734 million, Nevada Power's share is 60 percent and Sierra's share is 40 percent, to purchase, install, and operate a 400 MW solar PV project located in Churchill County, Nevada with an in-service date of April 2027.

ii. Approval of the Companies' request to amend their Supply Plan to expend approximately $731 million, Nevada Power's share is 60 percent and Sierra's share is 40 percent, to purchase, install, and operate a 400 MW, 4-hour, BESS project located in Churchill County, Nevada with an in-service date of July 2026.

iii. Approval of the Companies' request to designate Sierra Solar as a critical facility pursuant to NAC § 704.9484 and associated accounting treatment in the form of CWIP balances in rate base and project expenses after the in-service date recorded in a regulatory asset with a carrying charge.

iv. Waiver of NAC § 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the 400 MW Sierra Solar BESS project;

v. Approval of the Companies' request to amend their Transmission Plan to expend approximately $71 million to construct transmission infrastructure needed to support the interconnection of the Sierra Solar PV & BESS projects.

c. Tracy 4/5 Continued Operation

i. Approval of the Companies' request to amend their Supply Plan to accommodate the continued operation of the Tracy Units 4/5 through 2049.

ii. Approval of the Companies' request to amend their Supply Plan to expend approximately $54 million for compliance with environmental regulations to enable the continued operation of Tracy 4/5 past 2031.

3. Approval of the Companies' request to amend the Generation Plan for regulatory asset treatment of the decommissioning of coal and coal combustion residuals operations at the Valmy Generating Station.

4. Approval of the Companies' request to amend the Renewables Plan to expend funds for the asset purchase of the Crescent Valley project for the future development of a 149 MW PV and 149 MW BESS project known as Crescent Valley Solar located in Lander County, Nevada.

5. Approval of the Companies' request to amend their Transmission Plan to expend approximately $56 million to construct the Esmeralda 525/230 kV Transformers.

6. Approval of the Companies' request to amend their Transmission Plan to expend approximately $40 million to construct the Amargosa 525/230 kV Transformers.

7. Approval of the Companies' request to amend their Transmission Plan to construct necessary infrastructure for the Apex Area Master Plan with the following projects:

a. Expend approximately $62 million for Apex Central 230/12 kV Substation;
b. Expend approximately $15 million for Apex East 230/12 kV Substation;
c. Expend $0.22 million for Apex Southeast 230/12 kV Substation constraint study, environmental studies, permitting and land acquisition efforts;
d. Expend $0.17 million for Apex Southwest 230/12 kV Substation constraint study, environmental studies, permitting and land acquisition efforts.

8. Waiver of NAC § 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the Valmy BESS project if the Commission approves the project;

9. Grant the request for confidential treatment of information contained in the Joint Application as described above;

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

Dated this 21st day of August, 2023.

Respectfully submitted,

NEVADA POWER COMPANY
SIERRA PACIFIC POWER COMPANY

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EXHIBIT A
NARRATIVE

SECTION 1. INTRODUCTION

Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy") are filing this Fifth Amendment ("Fifth Amendment") to their 2021 joint integrated resource plan ("2021 Joint IRP" or the "Plan").[1]

This Fifth Amendment provides a complete solution to the timely retirement of coal combustion at the North Valmy Generating Station ("Valmy") and the need for voltage support and available around-the-clock generation in the Carlin Trend load pocket. In addition, it addresses capacity and renewable portfolio standard ("RPS") concerns created by incremental cancellations and delays of previously approved projects, which aggravate persistent concerns about the uncertain availability of regional market capacity and energy. The filing continues to advance the state's objectives to become a leading producer and consumer of renewable energy while supporting growth in the state.

Across the country, 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 in a manner that also balances resource adequacy and reliability. All of the plans put forth in this Fifth Amendment advance the Companies' portion of the state's 2050 clean energy goal signed into law in 2019 in Senate Bill 358 ("SB358").

Nevada's energy evolution remains dynamic as the West continues to experience capacity shortfalls during peak usage periods. As described in the Fourth Amendment to the 2021 Joint IRP ("Fourth Amendment"), this has resulted in significant shortfall risk throughout the West with multiple states experiencing energy emergency alerts over the last several years. Nevada is not immune and has experienced energy supply issues three years in a row. As discussed in recent IRP filings, Nevada's historic level of reliance on the energy market to meet peak period demand is no longer the most reliable and economic direction and has introduced significant risk of energy shortfalls and associated rolling blackouts[2] in recent years. The Fifth Amendment utilizes the load forecast filed in the Third Amendment to the 2021 Joint IRP ("Third Amendment"), which indicated increased summer peak and energy demand related to both native load growth and

[1] Pursuant to Nevada Revised Statutes ("NRS") § 704.744, the Companies met on July 19, 2023, with the Commission's Regulatory Operations Staff ("Staff"), the Bureau of Consumer Protection ("BCP") and interested parties to present their 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.

[2] The term rolling blackout was described in the summer readiness compliance filing and flyer in the Resource Adequacy Investigatory Docket that has been ongoing since the summer of 2020. *See* Docket No. 20-08014, May 22, 2022, Comments. In the event NV Energy is unable to meet the energy needs of its customers (resource insufficiency), it will be directed to shed load. During a load shed event, blocks of customers will experience a power outage for approximately one hour at a time - a rolling blackout. While NV Energy has not initiated a load shed event to date, in recent summers an energy emergency alert level three has been declared, indicating a load shed event is imminent.

transportation electrification. NV Energy continues to focus on reducing Nevada's exposure to uncertain market resources to meet peak demand and is working towards increased energy independence to ensure reliable service for our customers while supporting future economic and job growth in our state.

With the support of the Public Utilities Commission of Nevada ("Commission"), the Companies have made great strides in recent IRPs towards the state's decarbonization goals, while also addressing changes in climate, weather, resource variability, and market conditions. For example, to address these changes, in 2020,[3] the Companies updated the use of Effective Load Carrying Capability ("ELCC") to better address the increasing quantities of variable renewable resources. 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. The First Amendment to the 2021 Joint IRP ("First Amendment") added renewable resources and upgrades to existing turbines to continue to reduce the open position, defined as the portion of the Companies' resource adequacy needs that are not met by resources under utility ownership or long-term contract. The Third Amendment introduced the Transportation Electrification Plan and presented a new load forecast. Finally, the Fourth Amendment continued operation of existing turbines and added new geothermal resources to address market availability concerns while continuing to advance Nevada's renewable energy future.

While the 2021 Joint IRP and the First and Fourth Amendments reduced the reliance on market capacity relative to prior plans, the Companies' focus remains on this effort to reduce risk and help ensure resource adequacy, especially in light of continuing cancellations and delays of previously approved projects. This effort towards energy independence moves in lockstep with expected resource sufficiency requirements of a future market or regional transmission organization. Alongside this effort, the Fifth Amendment continues to advance a decarbonized future by targeting the state's 2050 clean energy goal. This filing takes a balanced approach in the efforts towards energy independence by proposing a portfolio that includes more renewable and energy storage resources while continuing operation of natural gas generation resources.

The Preferred Plan in this Fifth Amendment ("Preferred Plan") uses the load forecast presented in the Third Amendment, addresses state and federal carbon policy and changes in fuel and purchase power prices, meets or exceeds the RPS in every year, advances the state's 2050 clean energy goal, and meets the 16 percent PRM for each utility. NV Energy respectfully requests that the 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 Fifth Amendment builds on the advances in recent filings and addresses ongoing and emerging resource adequacy concerns to ensure reliable and reasonably priced electric service can

[3] *See* Docket No. 20-07023.

be delivered to customers through prudent and practical long-term planning. Specifically, the Fifth Amendment:

1. Provides a complete solution to the timely retirement of coal combustion at Valmy and the need for voltage support and available around-the-clock generation in the Carlin Trend load pocket;
2. Addresses capacity and RPS concerns created by cancellations and delays of previously approved renewable projects;
3. Addresses continuing concerns about the availability and deliverability of regional market capacity and energy, which simultaneously advances resource sufficiency as required for participation in Western Resource Adequacy Program ("WRAP"), or a future market or regional transmission organization ("RTO"); and
4. Continues to advance the state's objectives to become a leading producer and consumer of renewable energy,[4] while supporting growth in the state.

1. The Fifth Amendment provides a complete solution to the timely retirement of coal combustion at Valmy and the need for voltage support and available around-the-clock generation in the Carlin Trend load pocket.

As described in the Generation section of the 2021 Joint IRP,[5] Valmy generation provides both capacity and critical system support in the Carlin Trend load pocket. A new transmission study described in the Transmission Section of this Fifth Amendment identified the need for operating or quick-start generation at or near Valmy at all times until Greenlink West is in service. This requires dispatchable resources with around-the-clock availability and without runtime limitations to be located at or near Valmy.

In the 2021 Joint IRP, the Iron Point and Hot Pot solar photovoltaic ("PV") and battery energy storage system ("BESS") projects were identified as replacement for the coal-fired Valmy Generating Station, providing both capacity and the identified system support needs, while also contributing to the RPS. With the removal of these two projects in the Fourth Amendment and the new system support requirements identified in the Transmission Section of this Fifth Amendment for the Carlin Trend load pocket, the Companies propose a different solution.

As described further in the Generation and Economic Analysis Sections of the narrative in this Fifth Amendment, the Companies evaluated different options to meet the system support requirement at Valmy. The options that required continued coal combustion at Valmy beyond 2025 were deemed least prudent due to the current risks and challenges of continued coal combustion and misalignment with the Companies' and the state's decarbonization goals. Coal supply and delivery remains a significant challenge for the entire region as demand for coal increased worldwide over recent years, leaving coal mines and railroads working to catch up to

[4] SB358, codified at NRS § 704.7820.
[5] *See* Docket No. 21-06001, Joint Application Vol. 14 at 141-42.

production and transportation needs. The Companies have observed higher market quotes for coal and the quality of coal continues to diminish as compared to years past. In addition, regulatory efforts continue to target coal combustion as described in the Generation Section of the narrative in this Fifth Amendment, adding layers of uncertainty to options for future coal combustion at Valmy. These coal supply and regulatory issues highlight the importance of ensuring a timely retirement of coal combustion at Valmy.

The Preferred Plan seeks to amend the Generation portion of the supply side plan with the repowering, or refueling, of the Valmy units to natural gas, providing a complete solution to the timely retirement of coal combustion at Valmy, while simultaneously ensuring the system support requirements in the Carlin Trend load pocket are met. Repower, or refuel, is defined as the conversion of coal-fired combustion to natural gas-fired combustion through refurbishing the existing steam boiler and steam turbine for generation.

As described in the Generation Section, a decision on the Valmy solution is essential at this time due to the limited time remaining until coal fired operation is scheduled to cease and new environmental regulations restrict operation of the Valmy Units. For the natural gas conversion to be complete and coal fired operation to cease by the end of 2025, the Engineering, Procurement and Construction ("EPC") contract will need to be issued immediately after the Commission order in this Docket. The certainty of an order on the Valmy solution in this Docket will also provide the certainty needed for the permitting and modification to the State Implementation Plan ("SIP") for Regional Haze urgently necessary for the Valmy solution gas conversion, as described in detail in the Generation Section. Timely completion of the Valmy solution would require approval in this docket.

The Valmy solution – the repower project costs and continued operation – presented in the Preferred Plan is based on the assumption that Idaho Power Company will continue to participate in the Valmy Station with its 50 percent ownership, sharing 50 percent of the output and cost. The Companies have been in thorough discussion with Idaho Power Company regarding their continued participation in the Valmy Generating Station. Idaho Power Company has indicated its interest in participating in the repower and is expected to file an IRP in the fall of 2023, requesting approval from the Idaho Commission. In the event the Nevada Commission approves the Companies' Preferred Plan and Idaho Power Company does not participate in the repower, the Companies will evaluate the impact to Nevada customers, and if appropriate, make a filing seeking Commission approval to complete the full Valmy Repower, bear all associated costs, and receive the full capacity of both repowered Valmy units. To be clear, the current plant agreements with Idaho Power Company do not allow for this option and, consequently, this option is not being presented as one of the alternative plans. The Companies will provide status updates to the Commission after Idaho Power Company has filed its resource plan (currently anticipated in the fall of 2023). Subsequently, if the Commission approves the Companies' Preferred Plan while Idaho Power Company's resource plan is still pending, the Companies can update the Commission through a compliance filing once the final decision is made regarding Idaho Power Company's resource plan by the Idaho Commission.

Repowering Valmy with natural gas aligns with the state's and the Companies' decarbonization goals and achieves the retirement of coal combustion at the end of 2025. With the retirement of coal combustion at Valmy, the Companies will have accomplished the removal of all coal combustion from the Companies' supply portfolio.

2. The Fifth Amendment addresses capacity and RPS concerns created by cancellations and delays of previously approved renewable projects.

Risks to timely completion of approved renewable projects, highlighted in the Fourth Amendment, have been realized in this filing. Renewable project developers continue to struggle to meet their contractual obligations to the Companies to deliver Commission-approved renewable projects. In response, the Preferred Plan adds a renewable resource that mitigates cancellations and delays of previously approved renewable projects.

As stated in the First Amendment Stipulation,

> …renewable resources that are currently under development could face delays, shortfalls, and/or cancellations, due to the various market conditions surrounding the solar PV and BESS markets, such as the 2020 global shutdowns, and the on-going lockdowns in places such as Shanghai caused by COVID-19 which limit manufacturing and shipping; the March 2021 blockage of the Suez Canal that created a global supply chain disruption; and the March 2022 Department of Commerce's decision to investigate solar panels and modules from Cambodia, Malaysia, Thailand and Vietnam, which effectively froze the imports into the U.S. Recently, President Biden declared a 24-month pause on the implementation of the import tariff underlying the investigation, and invoked the Defense Production Act to drive U.S. manufacturing of solar panels. It is not known how quickly the backlog of solar panel imports that was created by the Department of Commerce investigation can be cleared by the President's decree, or how long the global supply chain issues created by the global pandemic will last. (Internal citations omitted.)[6]

And, as stated in the Fourth Amendment,

> Delays, shortfalls, and/or cancellations of any other renewable resources currently under development would increase the Companies' open capacity positions, causing increased reliance on an uncertain market, and shorten the time period of the Companies' forecasted RPS compliance periods.[7]

[6] Docket No. 22-03024, July 13, 2022, Order, Attachment 1 at 7.
[7] Docket No. 22-11032, December 1, 2022, Exhibit A – Narrative.

In addition to Hot Pot and Iron Point, the Companies had to remove two more projects, the Southern Bighorn Solar PV/BESS project approved in the Third Amendment to the 2018 Joint IRP and the Chuckwalla PV/BESS project approved in the Fourth Amendment to the 2018 Joint IRP, from the resource portfolio as well as delaying the commercial operation date of the Boulder Solar III PV/BESS project approved in the Fourth Amendment to the 2018 Joint IRP. These cancellations and delay are described in the Renewable Section of the narrative. Between Iron Point, Hot Pot, Southern Bighorn, and Chuckwalla, a combined 1,100 MW PV and 795 MW BESS have been cancelled, and for Boulder Solar III, an additional 128 MW PV and 58 MW BESS were delayed.

The Companies reviewed several resources when building the Preferred and Alternate Plans. The Preferred Plan seeks to amend the Renewable portion of the supply plan with the addition of the most cost effective of the renewable projects evaluated, the Sierra Solar 400 MW PV and 400 MW BESS resource, which provides the renewable generation during the daylight hours to contribute to RPS requirements and also contributes capacity in the evening hours after solar production has dropped off. The Companies seek designating Sierra Solar as a critical facility with incentives that consists of construction work in progress ("CWIP") balances in rate base and project expenses after the in-service date recorded in a regulatory asset with a carrying charge.

3. ***The Fifth Amendment addresses continuing concerns about the availability and deliverability of regional market capacity and energy, which simultaneously advances resource sufficiency as required for participation in WRAP or a future market or RTO.***

As noted in recent filings, western energy markets are experiencing rapid and significant changes in climate, weather, resource mix, policy, and energy consumption patterns, 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, addressing changes in weather through the use of new trended weather load forecasts, and taking steps regarding concerns about market availability, the concern and focus remain on the uncertain availability and deliverability of market capacity and energy.

Both the Western Electric Coordinating Council ("WECC") and the North American Electric Reliability Corporation ("NERC") have issued resource adequacy and reliability cautionary statements regarding the uncertain availability and deliverability of market capacity and energy due to more frequent extreme weather, weather-related events, and a changing climate that are stressing the system.

The 2022 Western Assessment of Resource Adequacy Report, published by WECC on November 1, 2022, acknowledges actions taken after the 2020 heat wave that strengthened resource adequacy, specifically calling out the addition of new or expedited resources and the delayed retirement of existing dispatchable resources. However, the report expresses continued concern for the region, stating:

> The West is experiencing rapid and significant changes in climate, weather, policy, energy consumption patterns, and technology that are challenging the industry's ability to reliably operate and maintain the grid. These changes, coupled with a rapidly transforming resource mix and push for electrification, create risks that will continue to grow over the next decade. These changes are affecting resource adequacy today and are expected to have increasing impacts in future years. There is an urgent need for the West to address resource adequacy issues now.[8]

The report also specifically discusses regional reliance on imports and points to the risk that "during some hours, under certain circumstances, these imports may not be available,"[9] identifying both availability and deliverability concerns.

NERC highlighted similar findings in their 2023 Summer Reliability Assessment ("2023 SRA") published in May 2023.[10] According to the 2023 SRA, the Western Region is exposed to energy shortfall risks in the near-term assessment period from wide-area and long duration extreme weather events such as the regional heat waves seen during the summers of 2020 and 2021. Additional details include:

- Wide-area heat events can expose the WECC assessment areas of California/Mexico (CA/MX), Northwest (NW), and Southwest (SW) to risk of energy supply shortfall as each area relies on regional transfers to meet demand at peak and the late afternoon to evening hours when energy output from the area's vast solar PV resources is diminished.

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.

- Wildfire risks to the transmission network, which often accompany these wide-area heat events, can limit electricity transfers and result in localized load shedding.

- WECC-NW would need to rely on imports to maintain adequate reserves on the peak riskiest hour (five hours later at 9:00 p.m.) under an extreme summer peak load and either extreme thermal or extreme hydro derates or any combination of two other extreme derate scenarios… Load shedding may be needed under extreme peak demand and outage scenarios.

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[8] WECC, 2022 Western Assessment of Resource Adequacy at 2, available at www.wecc.org/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.
[9] *Id*. at 5 and 44.
[10] NERC, 2023 Summer Reliability Assessment, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

The risks highlighted by both WECC and NERC have now manifested themselves for three consecutive summer seasons as extreme climate related incidents no longer appear to be isolated events. While previously described in the Fourth Amendment, the following events that impacted the Companies in the summers of 2020, 2021, and 2022 bear repeating.

In August of 2020, the western United States experienced an extreme and prolonged heatwave that resulted in record loads and, ultimately, rolling blackouts for the California Independent System Operator ("CAISO"). On August 18, 2020, due to the strain across the entirety of the Western Interconnection, the Companies experienced significant supply curtailments due to the extreme conditions 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.

In July of 2021, the Companies experienced a similar event. On July 9, 2021, NV Energy again experienced an 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[11] 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.

Another West-wide heat wave took place in September of 2022 as the first week of the month proved to be one of the most challenging periods on record for the western electrical grid. Given the intensity and duration of the event, this heat event ranked as one of the worst heatwaves in the past 40 years for the western United States. Temperature records were broken in major cities throughout the West including San Francisco, Salt Lake City, Billings, Boise, Reno, Las Vegas, and Sacramento. NV Energy exceeded its previous all-time September peak six different times with a new record peak for the month of September of 7,752 MW (previous peak was 7,304 MW set in 2021). September 6 in particular was extremely challenging for nearly all western entities. On this day, CAISO peaked at 52,061 MW, a new all-time record, and narrowly avoided rolling blackouts. In addition, the WECC as a whole peaked at 167,499 MW which was also a new record. On the evening of September 6, six entities issued some level of EEA including CAISO, Idaho Power, and the Western Area Lower Colorado Balancing Authority, who all issued level 3 emergencies. Available energy supply in the market was limited and prices reached as high as $1,900/MWh.

These concerns continue to be compounded by CAISO change in day-ahead export priorities implemented in the summer of 2021, its ongoing Wheel Through Initiative, and the recent change to e-tag rules that introduced a new firm provisional energy priority starting in July of 2023. The

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

2021 change to export priorities allows CAISO to adjust day-ahead export schedules to zero with potentially less than an hour's notice on whether the energy will flow. Following up on this change were new rules for tagging exports from CAISO that were implemented on July 1, 2023, as a part of the EIM Resource Sufficiency Evaluation Enhancement Phase 2 initiative. The rule change requires low-priority exports to be tagged as firm provisional energy in contrast to the historical practice of tagging the energy as standard firm energy. While firm provisional energy does technically meet the qualifications of WSPP Schedule C (firm) energy, significant curtailments to CAISO exports have already occurred in the short time since the rule changes were implemented. CAISO has stated the lower priority exports can be curtailed according to existing tariff rules and are easier to identify for manual curtailment in an EEA3 event. However, on the evening of July 25, 2023, NV Energy experienced curtailments to its CAISO sourced supply of nearly 750 megawatts over the critical evening peak time period. This was despite CAISO being only in an EEA Watch situation and loads in California reaching only approximately 43,000 megawatts (far short of CAISO's peak load of 52,061 set in September 2022). In follow up discussions with CAISO leadership, it was made clear that exports from California can no longer be supported on a consistent basis going forward. The changes to Wheel Through priorities allow CAISO to prioritize use of Northwest imports to serve CAISO load, precluding short-term (less than 45-day) firm energy from being wheeled through California. All of these changes impact both the Companies and Open Access Transmission Tariff ("OATT") customers in Nevada. The Federal Energy Regulatory Commission ("FERC") issued an order extending the wheel-through policies approved for the summer of 2021 through May of 2024 and directed CAISO to report on progress towards a long-term approach. CAISO has neither filed nor received FERC approval of a replacement methodology. 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." All of these items add significant risk to the market as a whole as the liquidity in the real-time hourly power market has been reduced significantly as more entities have joined the Energy Imbalance Market ("EIM") and these changes continue to add risk for market purchases that are either purchased through CAISO market or wheeled through California.

This past winter provided short-term relief to the drought-stricken West with record amounts of rain and snowfall in some areas. Specifically, the U.S. Energy Information Administration ("EIA") reported a series of atmospheric rivers from December 2022 to January 2023 drenched parts of the western U.S. which helped establish significant snowpack at high elevations and replenished reservoirs after years of drought.[12] As highlighted in a recent May 24, 2023, article by S&P Global,

> Another big story so far this year has been heavy precipitation in the Western US, which saw well above-average precipitation. California, specifically, saw snow levels at 235% above normal. This is expected to lead to a spike in hydropower

[12] https://www.eia.gov/todayinenergy/detail.php?id=55599.

generation this summer to levels not seen since August 2019.[13]

While this has improved energy supply in the near-term, as of June 20, 2023, the current water storage at Lake Mead is only 31 percent full, which Hoover hydroelectric generation is dependent on, and Lake Powell is only 39 percent full, which Glen Canyon hydroelectric generation is dependent on.[14] One season of above-average precipitation will not solve the long-term uncertainties of hydroelectric facilities in the West, specifically those that are most impactful to the Companies. As highlighted in the NERC 2023 SRA as well, winter precipitation improved water supply for hydro generation in parts of the U.S. West, but low water levels on major reservoirs remain a concern for electricity generation.[15] The Companies remain prudent in monitoring hydroelectric capacity conditions in the West and the potential impacts on western energy markets.

Figure I-1 presents the near-term uncertainty in the Companies' capacity position going into this Fifth Amendment. This figure reflects the resources as approved in the Fourth Amendment as well as the loss of Southern Bighorn and Chuckwalla and delay of Boulder Solar III. **Figure I-2** demonstrates the Fifth Amendment's reduced reliance on uncertain market capacity. These two figures exclude resources that are already in operation; however, the proposed resources category in **Figure I-2** includes the continued operation of certain units as proposed in the Preferred Plan. These figures reflect the load forecast approved in the Third Amendment.

[13] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/052423-us-coal-fired-power-plant-retirements-hydropower-output-remain-important-this-summer.
[14] https://www.usbr.gov/lc/region/g4000/weekly.pdf.
[15] NERC, 2023 Summer Reliability Assessment, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

FIGURE I-1
POTENTIAL UNCERTAINTY IN NV ENERGY'S CAPACITY POSITION
FOURTH AMENDMENT REVISED CASE

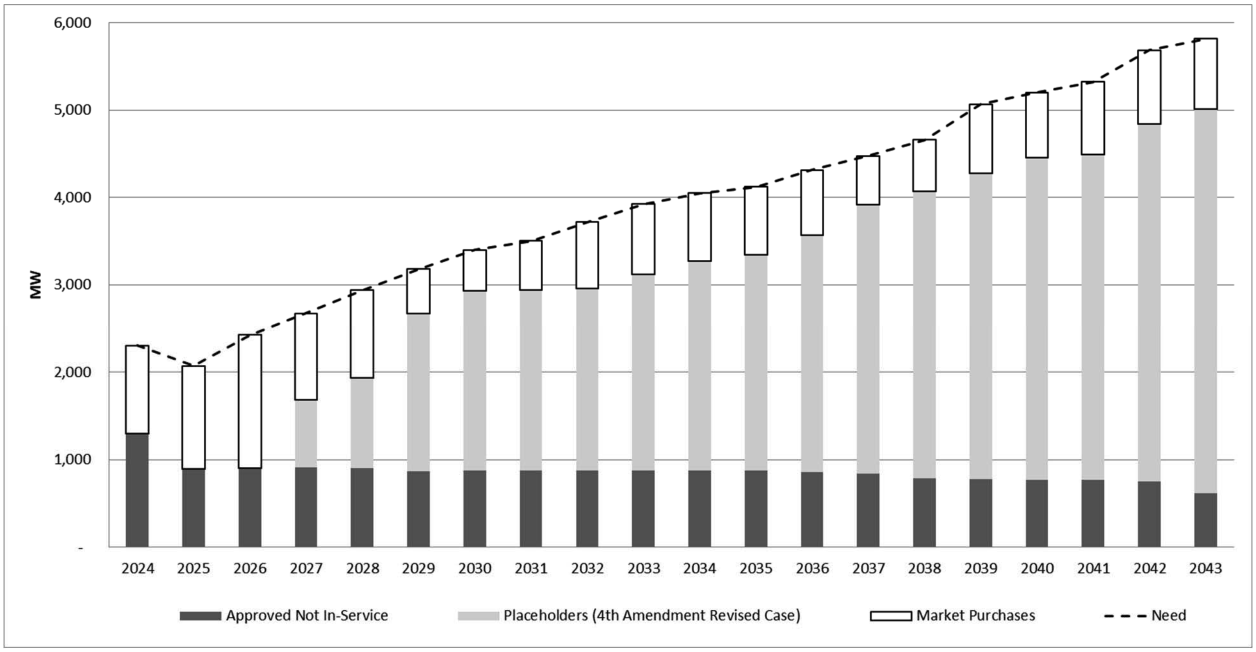
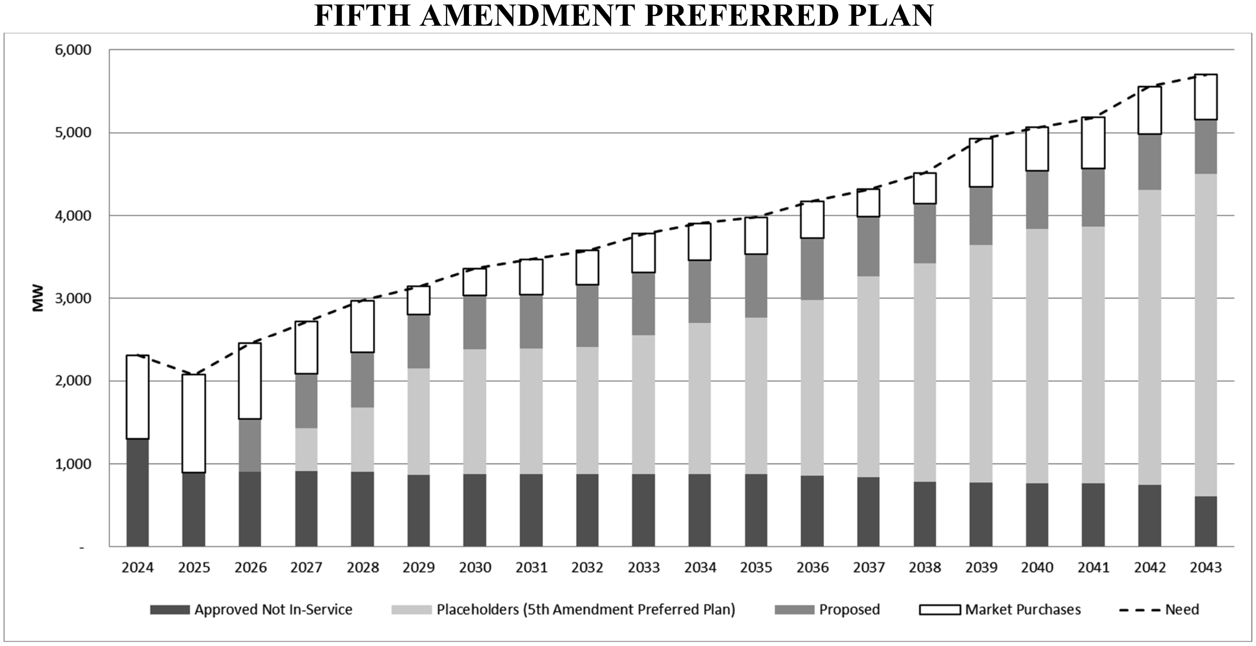


FIGURE I-2
POTENTIAL UNCERTAINTY IN NV ENERGY'S CAPACITY POSITION
FIFTH AMENDMENT PREFERRED PLAN



Cause continues to exist to doubt the availability and deliverability of regional market capacity and energy and, therefore, to limit the Companies' immediate reliance on it on a going-forward basis. The Preferred Plan addresses this through modest additions of diverse resources which aligns with meeting sufficiency requirements for future participation in WRAP or a future market or RTO, and better positions NV Energy for changing regional conditions due to climate change and increasing decarbonization in the West.

As an additional step to improve resource adequacy for the state of Nevada in the future, the Companies have been actively participating in the development of WRAP. WRAP is the first regional reliability planning and compliance program in the West, with 22 entities currently participating in the program. Its purpose is to deliver a region-wide approach for assessing and addressing resource adequacy and improving reliability for the region. The program has received support from state regulators across the West and the Committee on Regional Electric Power Cooperation submitted a letter to FERC strongly supporting the WRAP program. Signatories on the letter included Chair Williamson, Commissioner Cordova, and Commissioner Manthe.

As the program continues to be developed, the Companies have been participating in the latest phase of development (3B) that began on January 1, 2023. This new phase commenced a transitional period into the binding phase. In order to participate in the binding period of the program, the Companies will need to pass a forward showing requirement. The forward showing is a participating load-serving entity's plan to be resource adequate during each month of the binding winter or summer season. The forward showing utilizes the entity's monthly 1 in 2 peak (P50) forecasted load with the region's monthly PRM to calculate the entity's monthly requirement to become resource adequate. Each resource's capacity contribution is calculated by the program operator to apply only the capacity that would be available during the net load peak, also described as the capacity critical hours. The forward showing results apply the qualifying resource capacity towards the monthly requirement to determine whether the entity passes or fails the resource adequacy planning check. Any participant that fails the forward showing will be subject to penalties that utilize a cost of new entry charge, which is equal to the amount that it would cost to build new generation. It is important to note that market purchases may apply towards the forward showing, however, any contracts will need to satisfy strict requirements and limited market supply is available that meets the guidelines. Contracts must be in place ahead of the seven-month deadline to submit the forward showing for the binding season in order to count towards qualifying capacity for the forward showing. The contract must also include an identified physical source committed to the supply, provide assurance the capacity is not used for another entity's resource adequacy requirements, provide assurance the seller will not fail to deliver, and also commit that the energy will be delivered on firm transmission. Therefore, it may not always be possible for an entity to close forward showing shortfalls with contractual supply.

In response to the feedback received during the proceedings for the Fourth Amendment, the Companies worked closely with the Southwest Power Pool, the WRAP program operator, to provide the best estimate for the projected forward showing requirement for summer 2027 which is the first summer season NV Energy is expected to go financially binding. The results determined the largest deficiency occurs in July 2027 with a 1,670 MW resource shortfall. An additional scenario was completed showing the projected deficiency after including the resources proposed in the Preferred Plan. This scenario resulted in the deficiency shrinking to 1,035 MW in July 2027. The assumptions used for capacity contribution and the planning reserve margins in the forward showing requirement are preliminary estimates and subject to change as the WRAP program continues to be developed. However, these initial projections show the need for continued capacity additions to ensure the Companies are able to meet their forward showing obligations for participation in the WRAP.

4. The Fifth Amendment continues to advance the state's objectives to become a leading producer and consumer of renewable energy, while supporting growth in the state

As previously described, the Fifth Amendment advances the development of renewable energy in the state by adding a new renewable resource in the Preferred Plan. This Preferred Plan, like all of the alternative plans presented in this filing, targets the Companies' proportionate share of the state's 2050 clean energy goal. In addition, in this filing, the Companies proactively pursue future development opportunities and infrastructure to support growth in the state.

The Companies seek approval of the cost of the Crescent Valley Solar asset purchase agreement, which is a development opportunity that can contribute to future RPS compliance and capacity needs.

The Companies have received numerous applications for interconnection with more than 9,900 MW at the Esmeralda Substation, and nearly 5,000 MW at the Amargosa Substation along Greenlink West. As highlighted in the 2020 Fourth Amendment to the 2018 Joint IRP:

> Greenlink West creates the type of electrical network required to make Nevada a major hub in the western market both by its electrical interconnection, but also the additional access it creates to untapped renewable energy zones. The Amargosa Valley, Gold Point and Millers solar energy zones encompass thousands of MW of solar potential with no current transmission access. Greenlink West passes directly alongside all three of these zones and will be designed in a manner that creates isolation points along the line with two collector substations. These substations can be utilized to inject solar into the intertie and deliver it to and from Nevada.[16]

The commercial operating dates in these interconnection applications are as early as 2026. To minimize costs through economies of scale with current Greenlink procurement activities and to accommodate timely interconnection of renewable resources, the Companies request approval for the Esmeralda and Amargosa 525/230 kV transformer additions.

[16] Docket No. 20-07023, July 20, 2020, Exhibit A – Narrative.

Nevada continues on a steady growth trajectory and the Companies are proactively planning for an expected high growth area. While the Companies are not proposing a revised load forecast in the Fifth Amendment, the Apex area located in the City of North Las Vegas has the potential for substantial load and generation growth. The Companies have received numerous applications for load service in the Apex area. In June 2023, Senator Catherine Cortez Masto, D-Nevada, introduced legislation to help with Apex area development by improving the permitting process to allow businesses to get the utilities they need to operate. The Companies seek to amend the Transmission Plan with incremental components of the Apex Area Master Plan, which includes Apex Central 230/12 kV Substation, Apex East 230/12 kV Substation, and preliminary study and permitting activities for Apex Southeast 230/12 kV Substation and Apex Southwest 230/12 kV Substation.

In conclusion, it is important to note that, as has become standard, this Fifth 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 are specifically focused on the complete Valmy solution as well as resource adequacy needs and provision of reliable, diverse supply that reduces reliance on market purchases while continuing to prioritize and meet all state goals and policies.

SECTION 2. SUMMARY OF SPECIFIC APPROVALS REQUESTED AND CHANGES IN ASSUMPTIONS OR DATA SINCE THE FOURTH AMENDMENT TO 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 Fifth Amendment to the 2021 Joint IRP base long-term fuel and purchased 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. Valmy 1 & 2 Repower on Natural Gas

        i. Approval of the Companies' request to amend their Supply Plan to expend approximately $83 million, Sierra's share of the total project cost shared with Idaho Power Company, to repower existing coal-fired combustion to natural gas fired combustion at the Valmy Generating Station, with an in-service date of December 2025 for Valmy 1 and May 2026 for Valmy 2.

        ii. Approval of the Companies' request to amend their Supply Plan to accommodate the continued operation of the repowered Valmy Generating Station through 2049.

    b. Sierra Solar PV & BESS

        i. Approval of the Companies' request to amend their Supply Plan to expend approximately $734 million, with Nevada Power's share at 60 percent and Sierra's share at 40 percent, to purchase, install, and operate a 400 MW solar PV project located in Churchill County, Nevada with an in-service date of April 2027.

        ii. Approval of the Companies' request to amend their Supply Plan to expend approximately $731 million, with Nevada Power's share at 60 percent and Sierra's share at 40 percent, to purchase, install, and operate a 400 MW, 4-hour, BESS project located in Churchill County, Nevada with an in-service date of July 2026.

iii. Approval of the Companies' request to designate Sierra Solar as a critical facility pursuant to NAC § 704.9484 and associated accounting treatment in the form of CWIP balances in rate base and project expenses after the in-service date recorded in a regulatory asset with a carrying charge.

iv. Waiver of NAC § 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the Investment Tax Credit for the 400 MW Sierra Solar BESS project.

v. Approval of the Companies' request to amend their Transmission Plan to expend approximately $71 million to construct transmission infrastructure needed to support the interconnection of the Sierra Solar PV & BESS projects.

c. Tracy 4/5 Continued Operation

i. Approval of the Companies' request to amend their Supply Plan to accommodate the continued operation of the Tracy Units 4/5 through 2049.

ii. Approval of the Companies' request to amend their Supply Plan to expend approximately $54 million for compliance with environmental regulations to enable the continued operation of Tracy 4/5 past 2031.

3. Approval of the Companies' request to amend the Generation Plan for regulatory asset treatment of the decommissioning of coal and coal combustion residuals operations at the Valmy Generating Station.

4. Approval of the Companies' request to amend the Renewables Plan to expend approximately [redacted] for the asset purchase of the Crescent Valley project for the future development of a 149 MW PV and 149 MW BESS project known as Crescent Valley Solar located in Lander County, Nevada.

5. Approval of the Companies' request to amend their Transmission Plan to expend approximately $56 million to construct the Esmeralda 525/230 kV Transformers.

6. Approval of the Companies' request to amend their Transmission Plan to expend approximately $40 million to construct the Amargosa 525/230 kV Transformers.

7. Approval of the Companies' request to amend their Transmission Plan to construct necessary infrastructure for the Apex Area Master Plan with the following projects:

a. Expend approximately $62 million for Apex Central 230/12 kV Substation;
b. Expend approximately $15 million for Apex East 230/12 kV Substation;
c. Expend $0.22 million for Apex Southeast 230/12 kV Substation constraint study, environmental studies, permitting and land acquisition efforts;
d. Expend $0.17 million for Apex Southwest 230/12 kV Substation constraint study, environmental studies, permitting and land acquisition efforts.

8. Waiver of NAC § 704.6546, use of separate-entity method by utility members of consolidated group, to pass through to customers the full benefit of the ITC for the Valmy BESS project if the Commission approves the project;

9. Grant the request for confidential treatment of information contained in the Joint Application as described above;

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

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 stated above, the Preferred Plan addresses both state and federal carbon policy as well as changes in 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. The Common Methodologies and Assumptions subsection of the Financial Plan Section, Section 9 of the narrative, lists the key modeling assumptions used in the Financial Plan. The frequency of rate case cycles was adjusted from the rigid three-year cycles to various frequencies scheduled to support major capital investments. The assumed inflation rate was adjusted to 2.30 percent from 2.00 percent in the Fourth Amendment. The weighted average cost of capital for Sierra was updated to 6.95 percent from 6.75 percent in the Fourth Amendment. The assumed marginal cost of new long-term debt was updated to a range of 4.71 percent and 6.10 percent based on current pricing information from the Fourth Amendment range of 4.00 percent to 6.22 percent.

SECTION 3. LOAD FORECAST

The load forecast for the Fifth Amendment to the 2021 Joint IRP is identical to the load forecast that was approved on March 23, 2023 by the Order in Docket No. 22-09006 by the Commission, accepting the stipulation approving the latest load forecast. The load forecast will be updated in the 2024 triennial IRP for both population and economics inputs, reflecting the stipulated agreement in Docket No. 22-09006, as well as new major project load additions.

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 2023 through 2042 from the load forecast approved in Docket No. 22-09006. 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
2023	32,651	22,514	10,136	7,950	6,131	1,966
2024	33,462	22,971	10,492	8,133	6,222	2,015
2025	34,145	23,346	10,799	8,217	6,319	2,068
2026	34,092	23,569	10,523	8,267	6,371	2,049
2027	34,594	23,780	10,814	8,293	6,430	2,099
2028	35,162	24,059	11,102	8,536	6,524	2,142
2029	35,639	24,314	11,324	8,608	6,591	2,184
2030	35,906	24,494	11,411	8,777	6,645	2,206
2031	36,157	24,669	11,488	8,770	6,693	2,234
2032	36,439	24,881	11,558	8,826	6,742	2,257
2033	36,669	25,047	11,622	8,894	6,794	2,275
2034	36,946	25,261	11,686	9,026	6,879	2,299
2035	37,227	25,480	11,747	9,061	6,918	2,318
2036	37,556	25,743	11,812	9,181	6,986	2,341
2037	37,806	25,937	11,869	9,281	7,050	2,362
2038	38,082	26,157	11,925	9,244	7,106	2,380
2039	38,362	26,379	11,982	9,377	7,174	2,394
2040	38,673	26,638	12,035	9,477	7,257	2,411
2041	38,912	26,830	12,082	9,679	7,333	2,429
2042	39,199	27,065	12,134	9,667	7,404	2,450
CAGR						
23-33	1.2%	1.1%	1.4%	1.1%	1.0%	1.5%
32-42	0.7%	0.8%	0.5%	0.9%	0.9%	0.8%

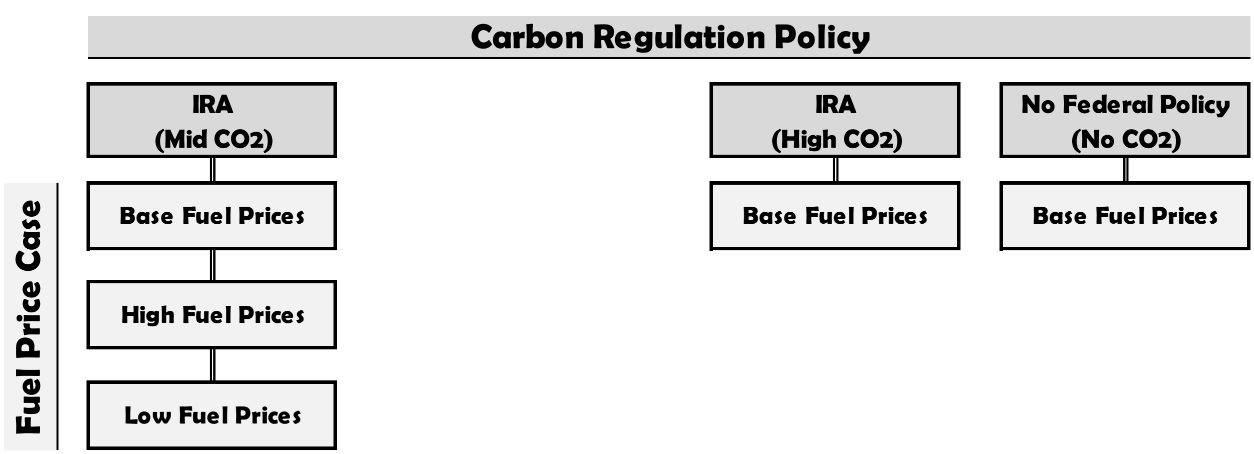
Notes:
(1) NVE Peak adjusted for diversity.
(2) Hourly value of Company coincident peak

SECTION 4. FUEL AND PURCHASED POWER PRICE FORECASTS

The fuel and purchased power ("F&PP") price forecasts in this Fifth Amendment, compared to the 2021 Joint IRP, are based on higher observed power and natural gas market quotes used in the short-term forecast, as well as a higher, newly released long-term market fundamental price forecast. These price forecasts are presented in this Section of the Amendment. The Companies have followed the F&PP price forecast provision from Docket No. 22-03024 pertaining to the use of high and base price F&PP price forecasts.[17] Since the high price F&PP forecast filed in the First Amendment to the 2021 Joint IRP is higher, in the months of April through November of 2023, than the base price F&PP forecast filed in this Fifth Amendment, the high price F&PP forecast was used for production cost modeling in the above-mentioned months. From December 2023 and onward, the base price F&PP forecast filed in this Fifth Amendment was exclusively used.

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. As described in subsection H, the assessment of federal climate change policy, also called carbon regulation policy, in this Amendment is influenced largely by the 2022 Inflation Reduction Act ("IRA"). A total of five separate price forecast scenarios were developed to determine the impacts of both carbon regulation policy and fuel/purchased power price levels on production costs and resource options. Three price forecast scenarios—base, high and low fuel and purchased power prices were prepared. These forecast scenarios were used in preparing the analysis presented in this Amendment. Also, two alternative cases were prepared assuming base fuel and purchased power prices but imposing various levels of carbon regulation impact, mid CO_2 and high CO_2 (low CO_2 case is equal to no CO_2 case). All five cases are presented in Figure PF-1.

FIGURE PF-1
PRICE FORECAST SENSITIVITY SCENARIOS



[17] Docket No. 22-03024, July 13, 2022, Order at 3-4.

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 19-day trading period from February 1, 2023, through February 28, 2023.

Fundamental (long-term) forecast. The fundamental forecasts of power and natural gas prices are provided through a subscription service with Wood Mackenzie, Ltd. ("WoodMac"), a global energy, metals and mining 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 long-term outlook (Decarbonization Headwinds Update, released in February of 2023.)

A. Base Gas Price Forecast

The monthly gas price forecast by regional hub begins with the 19-day average of market quotes in the near-term forecast months, April 2023 through March 2025. For the intermediate-term months, April 2025 through March 2027, a blending process is used to gradually transition from the 19-day average quotes to the long-term fundamental natural gas price forecast from WoodMac.[18] 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.

[18] 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 [REDACTED]
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 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 million British thermal units ("MMBtu")) with monthly on-peak and off-peak market heat rates (in MMBtu 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 19-day average power price quotes and the 19-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 provides the base case forecast (Base Fuel-Mid CO_2) of average MIHRs for delivered energy to Nevada at the Mead trading hub, the main import hub for the Companies. Note that the MIHR declines as renewable penetration increases. Forecasts of average MIHRs for Mead and other relevant trading hubs are provided on a monthly basis in Technical Appendix FPP-1.

FIGURE PF-3 [REDACTED]
AVERAGE MARKET IMPLIED HEAT RATE FORECAST
(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 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 is presented in the Figure PF-4. Note that prices drop in the near term as renewable penetration increases, then rise later as fossil fueled plants retire and high-cost storage increases.

FIGURE PF-4 [REDACTED]
AVERAGE ANNUAL POWER PRICE FORECAST – MEAD
(BASE FUEL-MID CO_2)

[redacted]

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

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 February 2023 were used to calculate the volatility of natural gas futures for the period from April 2023 to September 2026. 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-5 and PF-6.

FIGURE PF-5 [REDACTED]
BASE, HIGH AND LOW GAS PRICE FORECAST – SOCAL

[redacted]

FIGURE PF-6 [REDACTED]
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.[20] The product of this calculation is added to the monthly spark spreads from the base case price forecast.[21] This methodology provides a reasonable estimate for market prices where natural gas-fired generation is setting market clearing prices, such as in Nevada.

[20] 7,000 Btu/kWh heat rate represents standard benchmark of new and efficient natural gas combined-cycle generator. U.S. ENERGY INFORMATION ADMINISTRATION, *Conversion Efficiency vs. Heat Rate*, April 18, 2013, available at https://www.eia.gov/todayinenergy/includes/sparkspread_explain.php.

[21] 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 average power prices at Mead trading hub (the main power import hub for the Companies) are graphed in Figure PF-7. The on-peak, off-peak and average power prices on a monthly basis for Mead and other relevant hubs are provided in Technical Appendix FPP-1.

FIGURE PF-7 [REDACTED]
BASE, HIGH, LOW POWER PRICE FORECAST – (MEAD AVERAGE)

[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; 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 the 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. The WoodMac fundamental forecast includes resource expansion modeling that incorporates the impact of unit retirements and resource additions. In preparation of this Amendment, the Companies have 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 annual capacity prices are shown in Figure PF-8.

FIGURE PF-8
PROJECTED CAPACITY PRICES [REDACTED]

[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 Valmy 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 markets 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 Valmy in dollars per unit of heat content ($/MMBtu) are developed and are shown below in Figure PF-9.

FIGURE PF-9
PROJECTED COAL PRICES [REDACTED]

[redacted]

H. Price Forecasts and Modeling of Potential Carbon Costs

The Companies have prepared fossil fuel price forecasts to evaluate the production cost impacts of proposed federal policy regarding carbon dioxide (“CO2”) emissions. The Companies’ base planning assumption includes the Mid-CO2 Policy scenario developed by NERA Economic Consulting (“NERA”) that includes the effects of this scenario on fossil fuel prices. Estimates of fossil fuel prices under the High-CO2 Policy scenario were also prepared. The Low-CO2 Policy scenario assumes federal climate policy has no effect on fossil fuel prices.

Federal carbon policy scenarios

NERA had for many years assumed that future federal climate policy will consist of a national cap-and-trade program for carbon dioxide emissions (in some cases only for the electric utility sector). This assumption was motivated initially by passage by the House in 2009 of a national cap-and-trade bill and later by the inclusion in the Clean Power Plan (“CPP”) of a potential cap-and-trade program for electricity sector carbon dioxide emissions under regulations promulgated by the Obama Administration under Section 111(d) of the Clean Air Act.
Two major climate policy developments in 2022 mean that this cap-and-trade approach is no longer appropriate for assessing federal climate change policy, at least in the near to medium term.

On June 30, 2022, the Supreme Court overturned the CPP, concluding that Section 111(d) does not provide EPA with the authority to regulate emissions based upon “generation shifting” such as would occur under a cap-and-trade program.

In August 2022, President Biden signed the IRA that, among many other provisions, included major extensions of subsidies for investments in renewable energy, including subsidies for utility-scale wind and solar facilities, as well as subsidies for other renewable energy and energy efficient projects.

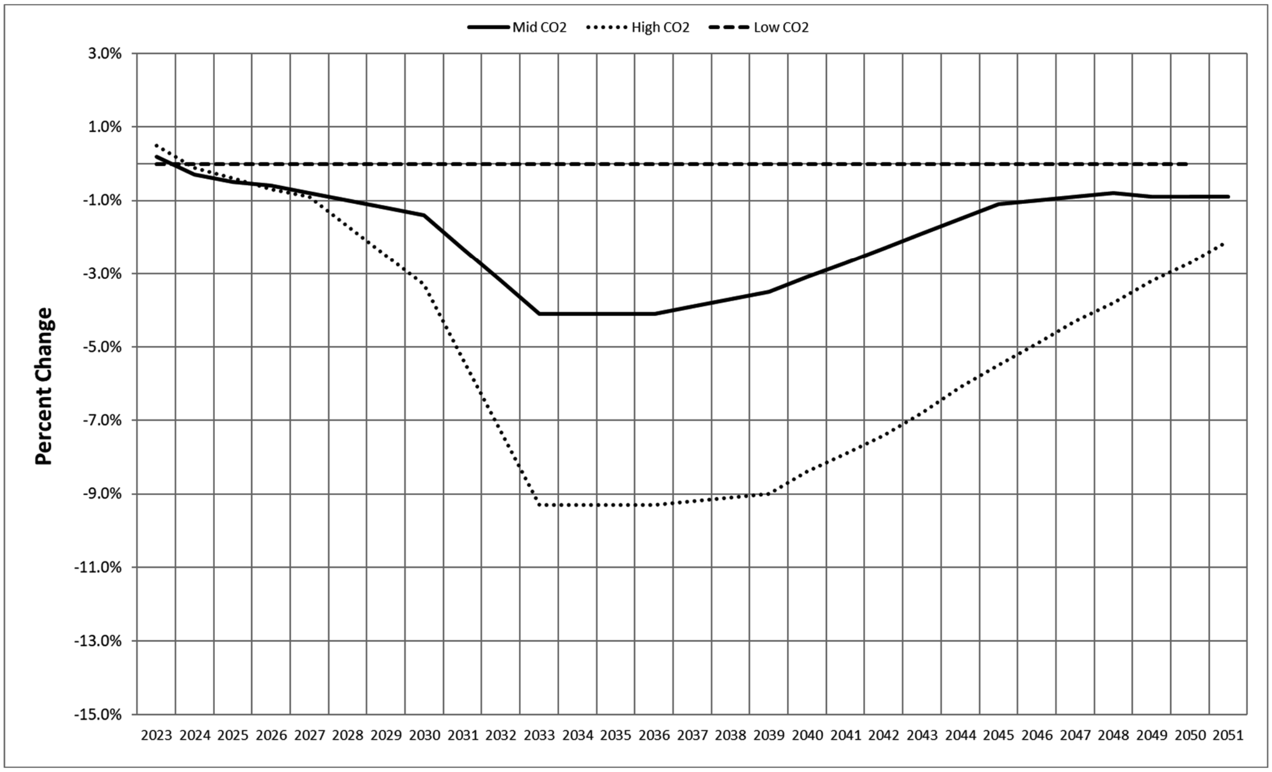
Because the IRA provides subsidies for investments in renewable energy and energy efficiency, the IRA results in decreases in the demand for fossil fuel energy (natural gas and coal). These decreases in demand will likely result in decreases in the prices of natural gas and coal, with the sizes of the decreases dependent upon the sizes of the various subsidies and the supply and demand elasticities for the fossil fuels, among other factors. For the Fourth Amendment, NERA developed partial and preliminary estimates of potential fossil fuel price impacts of the IRA because there was not sufficient time to use NewERA (NERA's electricity and energy market model). The Fourth Amendment estimates were limited to adaptation of prior modeling by others of policies similar to some of those in the IRA.

Fuel price impacts from federal carbon policy

For the Fifth Amendment, NERA had time to develop estimates of the major provisions of the IRA on fossil-fuel prices using NewERA. While there are many provisions of the IRA that might affect natural gas and coal prices, the most significant effects are likely to be due to the tax credit subsidies provided for renewable and other "clean energy" sources of electricity, for generation from existing merchant generation nuclear units, for residential renewable projects (such as roof-top solar), and for residential energy efficiency projects. NERA developed assumptions regarding the potential implementation of IRA provisions and used NewERA to model effects on natural gas and coal prices for a Mid-CO2 Policy scenario and a High-CO2 Policy scenario. NERA assumed that, under a Low-CO2 Policy scenario, the IRA would have no impact on fossil fuel prices.

The percentage adjustors to natural gas prices under the three climate policy scenarios modeled by NERA are shown in Figure PF-10.

FIGURE PF-10
NATURAL GAS PRICE ADJUSTMENTS FOR CARBON SCENARIOS
(HENRY HUB)



In its regional modeling of the WECC power markets, WoodMac in February 2023 published a Long-Term Outlook that assumes limited effects of the IRA on natural gas prices. The Companies applied the NERA price impacts (adjustors) to this WoodMac natural gas price forecast to create natural gas price forecasts under the three carbon policy scenarios for use in the PLEXOS generation dispatch modeling.

More detailed discussions of the carbon policy scenarios and the NERA modeling are provided in the direct testimony of Dr. David Harrison and the study of environmental costs and economic impacts prepared by NERA, Technical Appendix ECON-9, herein referred to as "NERA Report." As noted in the NERA Report, the future impacts on fossil fuel prices from future climate policies are highly uncertain due to various factors, including those related to IRA implementation and fossil fuel supply and demand elasticities, among others.

SECTION 5. SUPPLY 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 peak capacities):

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

- Chuck Lenzie Generating Station – Nevada Power: Chuck Lenzie Generating Station provides 1,182 MW of total peak summer capacity. The plant is located approximately 24 miles northeast of Las Vegas, Nevada, and is composed of two 2x1 natural gas-fired combined cycle units (591 MW per block).

- Clark Generating Station – Nevada Power: Clark Generating Station provides 1,162 MW of total peak summer capacity. Clark Generating 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 (678 MW). Clark Generating Station is located in Las Vegas, Nevada.

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

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

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

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

- Harry Allen Generating Station – Nevada Power: Harry Allen Generating Station provides 672 MW of total peak summer capacity. The Harry Allen Generating Station is comprised of the 510 MW natural gas-fired Harry Allen Combined Cycle facility and 162 MW of natural gas-fired combustion turbine peak summer capacity generated by two gas-fired turbine units (81 MW each). Harry Allen Generating Station is located 24 miles northeast of Las Vegas, Nevada.

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

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

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

- Silverhawk Generating Station – Nevada Power: Silverhawk Generating Station provides 590 MW of total peak summer capacity, including duct burners. The plant is comprised of one 2x1 natural gas-fired combined cycle unit and is located approximately 26 miles northeast of Las Vegas, Nevada.

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

- Tracy Station – Sierra: Tracy Station provides 773 MW of total peak summer capacity. Tracy Station is comprised of one natural gas-fired steam unit (92 MW), and two natural gas- fired combined cycle blocks (681 MW). Tracy Station is located approximately 15 miles east of Reno, Nevada.

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

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

TABLE GEN-1
GENERATING UNIT SUMMARY

Unit	Commercial Operation Date	Planning Retirement Date	Prime Mover[22]	Designation	Name Plate (MW)	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Primary Fuel Storage Capacity[23]	Secondary Fuel Storage Capacity
Sierra										
Brunswick	1960	2028	Recip	Peaker	6	6	6	Diesel	44 hrs.	0
Clark Mt. 3	1994	2044	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Clark Mt. 4	1994	2044	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Ft. Churchill 1	1968	2038	Steam	Intermediate	105	113	98	Nat Gas	0	0
Ft. Churchill 2	1971	2038	Steam	Intermediate	105	113	98	Nat Gas	0	0
Tracy 3	1974	2038	Steam	Intermediate	110	92	92	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	2048	CC /Steam	Base	623	578	589	Nat Gas	0	0
Valmy 1	1981	2025	Steam	Intermediate	127	127	127	Coal	200 days	200 days
Valmy 2[24]	1985	2025	Steam	Intermediate	134	134	134	Coal	200 days	200 days
Nevada Power										
Clark 4	1973	2035	CT	Peaker	60	63	55	Nat Gas	0	0
Clark 5, 6, 10	1979. 1979, 1994	2044	CC /Steam	Intermediate	236	250	230	Nat Gas	0	0

22 "CT" indicates combustion turbine, "CC" indicates combined cycle.
23 Fuel Storage Capacity Assumes Full Load Operation.
24 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.

Clark 7, 8, 9	1980, 1982, 1994	2043	CC /Ste am	Interme diate	236	250	230	Nat Gas	0	0
Clark 11 - 22	2008	2049	CT	Peaker	726	684	684	Nat Gas	0	0
Goodsprin gs	2010	2040		Base	7.5	6	5	Waste Heat	0	0
Harry Allen 3	1995	2046	GT	Peaker	72	84	81	Nat Gas	0	0
Harry Allen 4	2006	2046	GT	Peaker	72	84	81	Nat Gas	0	0
Harry Allen CC	2011	2049	CC /Ste am	Base	558	524	510	Nat Gas	0	0
Chuck Lenzie 1	2006	2049	CC /Ste am	Interme diate	610	601	625	Nat Gas	0	0
Chuck Lenzie 2	2006	2049	CC /Ste am	Interme diate	610	601	625	Nat Gas	0	0
Silverhaw k CC	2004	2049	CC /Ste am	Interme diate	599	599	617	Nat Gas	0	0
Walt Higgins CC	2004	2049	CC /Ste am	Interme diate	688	621	619	Nat Gas	0	0
LV Gen 1	1994	2049	CC /Ste am	Interme diate	61.3	51	48	Nat Gas	0	0
LV Gen 2	2004	2049	CC /Ste am	Interme diate	148. 8	115	112	Nat Gas	0	0
LV Gen 3	2004	2049	CC /Ste am	Interme diate	148. 8	115	112	Nat Gas	0	0
Sun Peak 3	1991	2041	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 4	1991	2041	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 5	1991	2041	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	180 hours[25]

25 No diesel fuel is currently stored on site

B. Environmental Regulations Impacts

Certain existing, recently promulgated and proposed environmental regulations are summarized below as they directly impact or may have future impacts on the operations of the Companies' generating units.

Regional Haze Rule

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

The RHR requires Nevada to address statewide emissions of visibility impairing pollutants that contribute to regional haze in each mandatory Class I Area ("CIA") located in Nevada and in each mandatory CIA located in nearby states. Jarbidge Wilderness Area located on the Nevada-Idaho border is the only mandatory CIA located in Nevada.

Under the RHR, Nevada is required to submit a State Implementation Plan ("SIP") addressing the specific elements required in the RHR. The Regional Haze second decadal planning period commenced in 2018, and the Nevada Division of Environmental Protection ("NDEP") filed a SIP revision with EPA in August 2022. The August 2022 SIP revision is currently under EPA review with a decision to approve or deny the SIP revision due by August 2023.

One of the elements required by the RHR is to conduct control analyses to determine what emission reduction measures will be necessary to make reasonable progress in each state's long-term strategy. States are required to select sources for analysis of control measures, identify emission control measures to be considered for these sources, and evaluate potential controls based on four statutory factors: costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life.

During the second decadal planning period, Tracy 4/5 (natural gas-fired) and both Valmy units (coal-fired) were identified as sources requiring four-factor analyses to evaluate existing controls and consider potential additional control measures that may be necessary to achieve reasonable progress during the second implementation period of the RHR in Nevada.

Table GEN-2 identifies the add-on nitrogen oxide ("NOx") and sulfur dioxide ("SO2") controls considered in the Valmy and Tracy four-factor analyses. Additional controls for particulate matter were also considered in the four-factor analyses.

TABLE GEN-2
EMISSION CONTROLS CONSIDERED
IN VALMY AND TRACY FOUR-FACTOR ANALYSES

NOx Control Measures	SO2 Control Measures
Selective Non-Catalytic Reduction (“SNCR”)	Limestone/Lime-Based Flue Gas Desulfurization (“FGD”)
Selective Catalytic Reduction (“SCR”)	Dry Sorbent Injection
Low NOx Combustion	Alternative Low Sulfur Fuels
Dry Low NOx (“DLN”) Combustion	Wet Scrubbing
Over Fired Air	Semi-Wet/Dry Scrubbing

Technically feasible NOx add-on control options for Tracy 4/5 included a retrofit with a DLN combustor or SCR. Tracy Units 4/5 combust only pipeline natural gas fuel, which minimizes emissions of SO2 and particulate matter. No further technically feasible emission controls for SO2 and particulate matter were determined to be feasible.

Valmy Unit 1 technically feasible NOx control options included SNCR or SCR and, for SO2 control, included Limestone/Lime-Based FGD. Valmy Unit 2 technically feasible NOx control options included SNCR or SCR. Valmy Unit 2 is already equipped with a lime slurry-based spray dryer to control SO2 emissions so no further technically feasible control options to lower SO2 were identified. No technically feasible emission control alternatives are available to reduce particulate matter emissions below the emission levels achieved using the baghouse filters that are currently employed on Valmy Units 1 and 2.

With the technically feasible control options identified for Tracy 4/5 and Valmy Units 1 and 2, the potential controls were evaluated based on the four statutory factors: costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life. At the time of the original evaluation, the book life or published retirement dates of 2025 for Valmy Units 1 and 2 and 2031 for Tracy 4/5 were used for the remaining useful life variable of the evaluation. Due to the short remaining useful life of the units, the technically feasible NOx and SO2 controls were not cost effective using a cost-effectiveness threshold, in $/ton reduced, of $10,000/ton.

Based on the four statutory factors, NDEP concluded that no new control measures were necessary to make reasonable progress towards visibility goals required by the RHR. NDEP then revised Tracy Station’s and Valmy Station’s Title V air permits to add federally enforceable retirement dates (requiring shut down and permanent cessation of operation) of December 31, 2031, for Tracy 4/5 and December 31, 2028, for Valmy Units 1 and 2.

In preparation for this Amendment, NV Energy met with NDEP to assess the steps necessary under the RHR to pursue projects allowing continued operation of both Valmy Units 1 and 2 and Tracy 4/5 in lieu of the current federally enforceable retirement dates. For Valmy Units 1 and 2, conversion to natural gas operation with appropriate NOx controls would need to be evaluated based on the four statutory factors. The technically feasible control technology to install NOx controls on Tracy 4/5 would also need to be re-evaluated for continued operations. For planning purposes, it was assumed that the most stringent controls (i.e., SCR) would be required in all cases. Recognizing that EPA is reviewing the SIP filed August 2022, NDEP intends to partially rescind the currently filed SIP prior to the EPA approval deadline in August 2023. It is imperative to pursue the Valmy and Tracy 4/5 modifications now such that revisions to the SIP and permits can be approved in a timely manner to allow for continued operation of these units as requested in this Amendment – through 2049. NDEP has also requested that the Companies commence revised four-factor analyses immediately to enable NDEP to update the SIP and make necessary permit modifications in parallel with this filing such that NDEP can submit a revised SIP to the EPA for their review as soon as possible if the proposed projects are approved by the Commission. If the Valmy and Tracy 4/5 projects are not approved by the Commission, it is expected that legally enforceable retirement dates in the currently filed SIP and the current Title V air permits – 2028 for Valmy and 2031 for Tracy 4/5 – will remain unchanged.

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

On February 13, 2023, EPA published a final action fully or partially disapproving SIPs with respect to the 2015 Ozone NAAQS, which included disapproval of the State of Nevada SIP. On March 15, 2023, EPA finalized the Federal Good Neighbor Plan for the 2015 Ozone NAAQS. The Good Neighbor Plan is also referred to as the “Ozone Transport Rule” or “Transport Rule.” The Good Neighbor Plan requires upwind states to reduce emissions of the ozone precursor NOx from electric generating units (“EGUs”) and certain stationary industrial sources. The Good Neighbor Plan was published in the Federal Register on June 5, 2023, with an effective date of August 4, 2023. On July 3, 2023, the United States Circuit Court of Appeals for the Ninth Circuit granted a stay of the final Good Neighbor Plan based on a petition filed by Nevada Cement Company. The State of Nevada filed a motion to intervene in this petition, which was granted by the court. Recognizing the recent stay issued by the court, the discussion below summarizes the Good Neighbor Plan presuming it would become effective after the petition is resolved.

The Good Neighbor Plan is implemented as part of a Federal Implementation Plan (“FIP”) by the EPA for 22 states, including Nevada. For EGUs, the Good Neighbor Plan sets states’ NOx emissions budgets and methodology to allocate emissions to individual EGUs during each control period (May to September ozone season). For control periods 2023 (prorated by EPA), 2024 and 2025, EPA establishes state budgets based on 2021 actual emissions, adjusted for known unit changes, such as a fuel conversion, and assumptions on optimizing emission controls on controlled units. The EPA reduces the state emission budget to allow for a new unit set aside, which is 9 percent each year for Nevada for 2023 through 2025 and is subsequently reduced to 5 percent in 2026 and subsequent years. The new unit set aside is intended to provide NOx allowances as new emission sources commence operation. To calculate allocations to each EGU for the control periods in 2023 through 2025, EPA uses heat input data reported for the control periods from 2017 through 2021 and reported emissions for the control period 2021.

The Good Neighbor Plan also includes state assurance provisions designed to limit the total emissions from all state sources in each control period to an amount close to the state's emissions budget, while allowing some collective flexibility beyond the emissions budget to accommodate year-to-year operational variability beyond the sources' reasonable ability to control. The variability limit is set at 21 percent of the state's emissions budget. The state's emission budget plus the variability limit is equal to the assurance level.

Each ton of NOx emitted requires submission of one allowance. NOx tons emitted above the assurance level require submittal of two additional allowances for each NOx ton emitted above the assurance level. This results in an overall 3:1 allowance submittal ratio for NOx tons emitted above the state assurance level. Further, NOx tons emitted above the state assurance level or in excess of allowances within a source's compliance account could be deemed a violation of the Clean Air Act ("CAA"), subjecting the source to additional fines, penalties, assessments, or other remedies imposed for the violation.

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

For existing, large coal-fired EGUs (rated at 100 MW or more), the Good Neighbor Plan will phase in the reduction of NOx allowances over a two-year period starting in 2026. In 2026, the NOx allowances for these units are based on an approximately 50 percent reduction from the 2021 emission rate for the affected unit (i.e., 50 percent of the sum of the unit's 2021 emission rate plus 0.05 lb/MMBtu). In 2027 and thereafter, NOx allowances are based on a fully controlled emission rate of 0.05 lb/MMBtu, commensurate with SCR retrofits. If the Valmy units are converted from coal-fired to natural gas generation, the emission rate for NOx may be further reduced by the EPA to a level of 0.03 lb/MMBtu reflecting gas-fired boiler operation.

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

For the current NV Energy fleet, the Good Neighbor Plan most directly impacts Valmy Units 1 and 2. In NV Energy's fleet, no large gas/oil-fired EGUs without SCRs were identified by EPA as being over 150 tons of NOx per ozone season. Optimization of fleet units with SCRs results in very small adjustments to NOx allowances – equivalent to rounding (e.g., one allowance). Clark Unit 4 was identified as requiring additional NOx emissions monitoring equipment beginning in 2024. Regardless, all NV Energy combustion EGUs, except for Brunswick, will be part of the Good Neighbor Plan.

In 2026, and thereafter, allowances allocated to Valmy Units 1 and 2 will be developed based on the dynamic budgeting process incorporating the reduced NOx emission rates as previously described. The dynamic budgeting process incorporates the following inputs to determine NOx allowances for each unit in the state: unit specific NOx emission rate, average of three highest heat input values from the prior five-year baseline for each unit, and the state-level heat input average from the latest three years. Because the Good Neighbor Plan requires reduced NOx emission rates for Valmy Units 1 and 2, the overall number of NOx allowances in year 2026 and future years are greatly reduced for Valmy Units 1 and 2, which also reduces the state's emissions budget and assurance level.

While final NOx allocations are not definitively known beginning in 2026, it is reasonably anticipated that Valmy coal-fired operation without installation of NOx controls in 2026 would likely be able to satisfy a must-run requirement at minimum load during the ozone season, but with limited ability from an NOx allowance perspective to support sustained high-load demands. In 2027 and thereafter, Valmy coal-fired operation would not be able to meet must-run requirements, if required, during the ozone season without installation of NOx controls.

While the Good Neighbor Plan also establishes a market-based allowance trading program, the liquidity and cost volatility for acquiring limited allowances is uncertain. Many transactions are currently privately brokered. EPA is evaluating an auction mechanism that would be anticipated to begin with the 2026 compliance period. Regardless of the ability to acquire additional allowances through the trading program, the state assurance levels cannot be exceeded without potential repercussions as described previously. EPA will also evaluate the need to recalibrate banked allowances if the total amount of banked allowances exceeds the target banked amount (21 percent for control periods through 2029 and 10.5 percent for each control period thereafter). The purpose of bank recalibration is to ensure that the emissions control stringency that EPA found necessary – to eliminate significant contribution to non-attainment or interfere with maintenance of the NAAQS downwind – is maintained over time and is durable to changes in the power sector. Bank recalibration ensures the elimination of significant contribution is maintained both in terms of geographical distribution (by limiting the degree to which individual sources can avoid making emissions reductions) and in terms of temporal distribution (by better ensuring emissions reductions are maintained throughout each ozone season, year over year).[26]

Proposed Greenhouse Gas Rule

On May 23, 2023, EPA published proposed regulations under CAA section 111 to address greenhouse gas ("GHG") emissions (primarily carbon dioxide emissions) from fossil-based EGUs, initiating a formal comment period that will end on August 8, 2023.

The proposal would set limits for new gas-fired combustion turbines, existing coal, oil and gas-fired steam generating units, and certain existing gas-fired combustion turbines.

The proposed standards are based on technologies such as carbon capture and sequestration/storage, low-GHG hydrogen co-firing, and natural gas co-firing, which can be applied directly to power plants that use fossil fuels to generate electricity.

The proposed New Source Performance Standard and emission guidelines reflect the application of the best system of emission reduction that, considering costs, energy requirements, and other statutory factors, is adequately demonstrated for the purpose of improving the emission performance of the covered electric generating units.

The proposed rule mostly affects coal-fired and large combustion turbine (combustion turbine plus apportioned steam turbine capacity greater than 300 MW) facilities. For the Valmy Units combusting coal, the proposed rule's requirements would not take effect until January 1, 2030, after the current Title V air permit retirement date of December 31, 2028. Should the Valmy Units 1 and 2 undergo fuel conversion to natural gas, the proposed rule would require gas-fired steam boilers to meet a 1,300 to 1,500 lb/MWh CO2 emission limit based on the unit's capacity factor. As proposed, the rule would also affect Nevada Power and Sierra combined cycle units greater than 300 MW. The draft rule does not affect Tracy Units 4/5 as the combustion turbine plus steam turbine capacity is under 300 MW.

Mercury and Air Toxics Standards

On April 3, 2023, EPA proposed to strengthen and update the National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units, commonly known as the Mercury and Air Toxics Standards, to reflect recent developments in control technologies and performance of these plants.

The proposal seeks to further limit the emission of non-mercury hazardous air pollutant ("HAP") metals by significantly reducing the emission standard for filterable particulate matter ("fPM"), which is designed to control non-mercury HAP metals. Along with other items, EPA is proposing

[26]Federal Register, Vol. 88, No. 107, June 5, 2023. Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards. Part I – Executive Summary, Page 4 of 265.

to strengthen emissions monitoring and compliance by requiring coal-fired EGUs to comply with the fPM standard using particulate matter continuous emission monitoring systems ("CEMS").

This proposed rule would only affect Valmy Units 1 and 2, which, based on historic emissions test data, generally show compliance with the proposed limit. Good, and potentially more frequent, baghouse maintenance would be required to ensure consistent compliance with the proposed limit. Additionally, each unit would be required to install, certify, operate and integrate a PM CEMS into the facility's existing system and begin data recording, quality assurance/quality control procedures and data reporting as required by the proposed rule.

C. Retirement Dates

In Docket No. 08-08002, Nevada Power proposed, and the Commission approved, the Life Span Analysis Process ("LSAP") to determine and reevaluate the economic useful lives of its generating units. Since that proceeding, both Companies have adopted the LSAP procedure, and they and the Commission have relied on this process for determining the appropriate depreciation planning retirement dates to be used for generating units.

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. For generating facilities that joined the Companies' fleet since the adoption of the LSAP, a unit's initial life span is established when the unit is first put in service. In the case of older units with in-service dates preceding the Commission's approval of the LSAP, the Reassessment Protocol set forth in the LSAP was used to set an initial life.

After a unit is commissioned and has been in operation, its life span may be reassessed to ensure that the Initial Life Span Assessment is still valid, or to determine a new plan that is more appropriate for the unit. The reassessment of unit life span can be undertaken for any of the following Reassessment Criteria:

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Change in Environmental Compliance Requirements
- Change in Infrastructure
- Significant Event
- Commission-Ordered Reassessment

When a reassessment is undertaken, it can range from cursory to detailed, depending on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the Initial Life Span Assessment. At the other end of the spectrum, a unit entering its planned last decade of operation may implicate operations, maintenance, environmental and infrastructure issues and could dictate a detailed review to assess the unit's remaining life span. No matter the nature of the review, the key steps of the Reassessment Protocol are as follows:

Unit Assessment
Environmental Assessment
Infrastructure Assessment
Development of Options
Options Input to Economic and Financial Analyses
Final Decision on Life Span Assessment and Implementation Plan.

In Docket No. 22-11032, the Companies were directed to provide a complete solution to the retirement of the Valmy coal units.[27] In this filing, the Companies are providing an LSAP for the Valmy Units (included as Technical Appendix GEN-3). Subsection D below provides discussion of Valmy solution pathways and key considerations, and Subsection E presents the proposed Valmy solution.

In addition, the Companies are providing an LSAP for Tracy 4/5 that considers an alternative to the current SIP retirement date of 2031 (included as Technical Appendix GEN-4). In this LSAP, the Companies studied the impact of adding a SCR system to the combustion turbine and continuing operations through 2049. This LSAP indicated that the Companies should pursue a change to the SIP and the current air permit to allow for the installation of the SCR and continued operation of the units. The project to install the SCR and complete the necessary plant repairs is described below.

D. Valmy Solution Pathways and Key Considerations

The current and proposed environmental regulations discussed in Section B are an important factor in selecting viable projects that would result in a Valmy solution that would cease coal-fired generation in a timely manner and meet system needs. System needs at the Valmy location are described in subsection A of the Transmission Section. For the purposes of this discussion, it was assumed a Valmy unit will need to operate under a must-run condition until Greenlink West is in service.

To illustrate the relationships between various relevant regulations and other requirements, a series of flowcharts were developed to evaluate a range of Valmy solutions, which are described below. Certain projects discussed as a Valmy solution are included in fully developed plans evaluated as part of this Amendment, while others, such as continuing coal-fired generation beyond 2028, are included simply to highlight potential challenges of pursuing these options.

Extend coal-fired generation until 2028: This pathway to continue coal-fired generation until 2028 with no replacement is included to highlight potential risks in extending coal-fired operations past 2025. This would align with the current legally enforceable retirement date for

[27] Docket No. 22-11032, June 12, 2023, Order at 64, para. 128.

Valmy Units 1 and 2 of December 31, 2028, established as part of compliance with the RHR.

Extend coal-fired generation beyond 2028: This pathway assumes that additional SOx and NOx emission controls on Unit 1 and NOx emission control on Unit 2 can be successfully permitted under current environmental regulations such that coal-fired generation may continue beyond 2028. This pathway has been provided for illustrative purposes only.

Natural gas conversion of existing units with NOx controls in 2026: This pathway assumes Valmy Units 1 and 2 are converted from coal-fired to natural gas-fired operation (also called refuel or repower) by May 2026. It also assumes the installation of NOx emission controls to comply with RHR and Good Neighbor Plan requirements.

Replace existing coal units with new natural gas-fired turbines in 2027: This pathway assumes that coal-fired generation continues until new natural gas-fired turbine units with NOx emission control can be installed. Once the new units are in operation, the coal-fired units would be retired.

Replace coal-fired generation with new solar PV and battery energy storage system (collectively, "PV/BESS") in 2026: This pathway assumes that coal-fired generation continues until new PV/BESS can be installed. Once the new PV/BESS units are in operation and after Greenlink West is in service, the coal-fired units would be retired.

<u>**Environmental Regulatory Pathways (Figure GEN-1)**</u>

The environmental regulations for each potential Valmy solution described above are illustrated on a timescale in Figure GEN-1. The primary objective of Figure GEN-1 is to show the timing and impact of environmental requirements, such as timing to install NOx emission controls to comply with the Good Neighbor Plan if it becomes effective in future years. The following observations were made for each Valmy solution pathway.

Extend coal-fired generation until 2028: Extending coal-fired generation until 2028 is technically feasible under the current permit requirements and regulations but does not result in a long-term Valmy solution. Under the Good Neighbor Plan, the ability to operate Valmy beginning in the 2026 ozone season until its retirement in December 2028 would be increasingly impaired due to reduced NOx allowances since Valmy does not have NOx emission controls.

Continue coal-fired generation beyond 2028: Extending coal-fired generation beyond 2028 would require SIP and permitting revisions to install SO2 and NOx emission controls on Valmy Unit 1 and NOx controls on Valmy Unit 2 as part of the RHR. Regulatory acceptance of this solution, while technically feasible to permit, may be challenging if other viable solutions exist. Under the Good Neighbor Plan, the ability to operate Valmy beginning in the 2026 ozone season until NOx emission controls are installed would be impaired. Future regulation, as illustrated by the proposed GHG rule, may require additional investment in emission controls to operate the units until 2049.

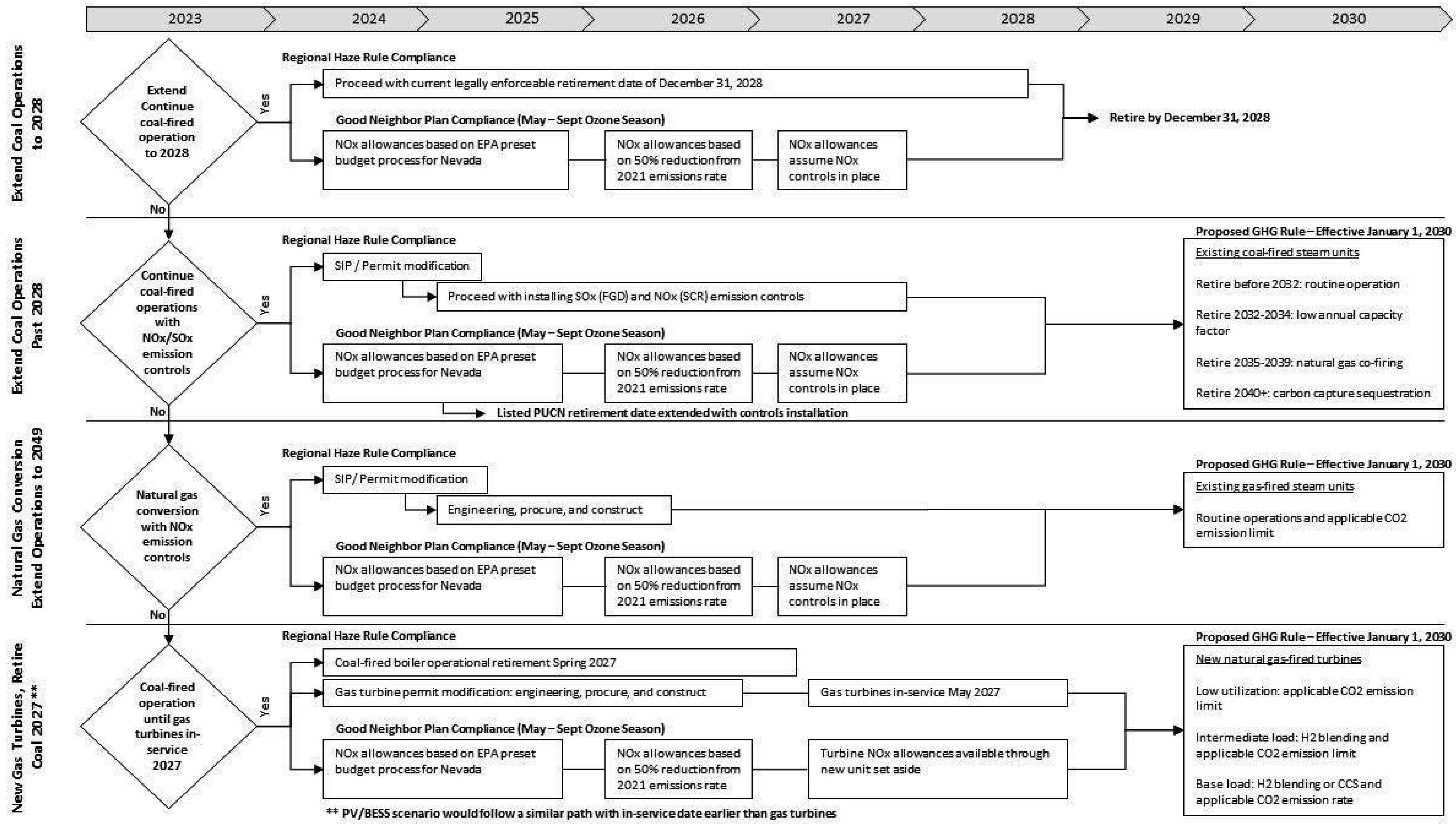
Natural gas conversion of existing units with NOx controls in 2026: Converting the Valmy units from coal-fired to natural gas-fired generation would also require SIP and permitting revisions. Installation of NOx controls anticipated under the RHR would also meet Good Neighbor Plan emission limits allowing for normal operation beginning with the 2026 ozone season, assuming the conversion is complete. Phasing in the conversion of the two units may also allow cessation of coal-fired generation by December 2025 if one unit is converted by that time. CO2 emissions following the conversion are expected to meet the levels proposed in the GHG rule; therefore, the stated carbon emission limits under the proposed GHG rule would not impede continued operation as a gas-fired steam unit through 2049.

Converting from coal to natural gas would also result in reduced carbon emissions, as CO2 emissions per MMBtu are about 50 percent less for natural gas relative to coal. Actual emission rates and reductions would vary based on type of operation (i.e., combustion turbine, steam boiler) and actual operations.

Replace existing units with new natural gas-fired turbines in 2027: Replacing the Valmy coal-fired units with new NOx emission controlled natural gas-fired turbines would require a permit modification. New units would also meet Good Neighbor Plan NOx emission limits allowing for normal operation during the ozone season. However, this pathway would require must run of a coal-fired unit until Greenlink West is in service and, under the Good Neighbor Plan, the ability to operate the existing coal-fired units at Valmy beginning in the 2026 ozone season would be impaired. Future regulation under the proposed GHG rule may pose additional operating requirements starting 2030 if the new turbines operate at levels greater than low utilization as determined by the state on a unit specific basis if the rule were implemented.

Replace existing units with new PV/BESS: The PV/BESS scenario follows a similar path to the installation of new gas turbines as noted at the bottom of Figure GEN-1. Replacing the Valmy coal-fired units with new PV/BESS would not require any SIP revisions or air permit modifications. However, this pathway would require must run of a coal-fired unit until Greenlink West is in service and, under the Good Neighbor Plan, the ability to operate the existing coal-fired units during the 2026 ozone season would be impaired.

FIGURE GEN-1
VALMY ENVIRONMENTAL REGULATORY PATHWAYS

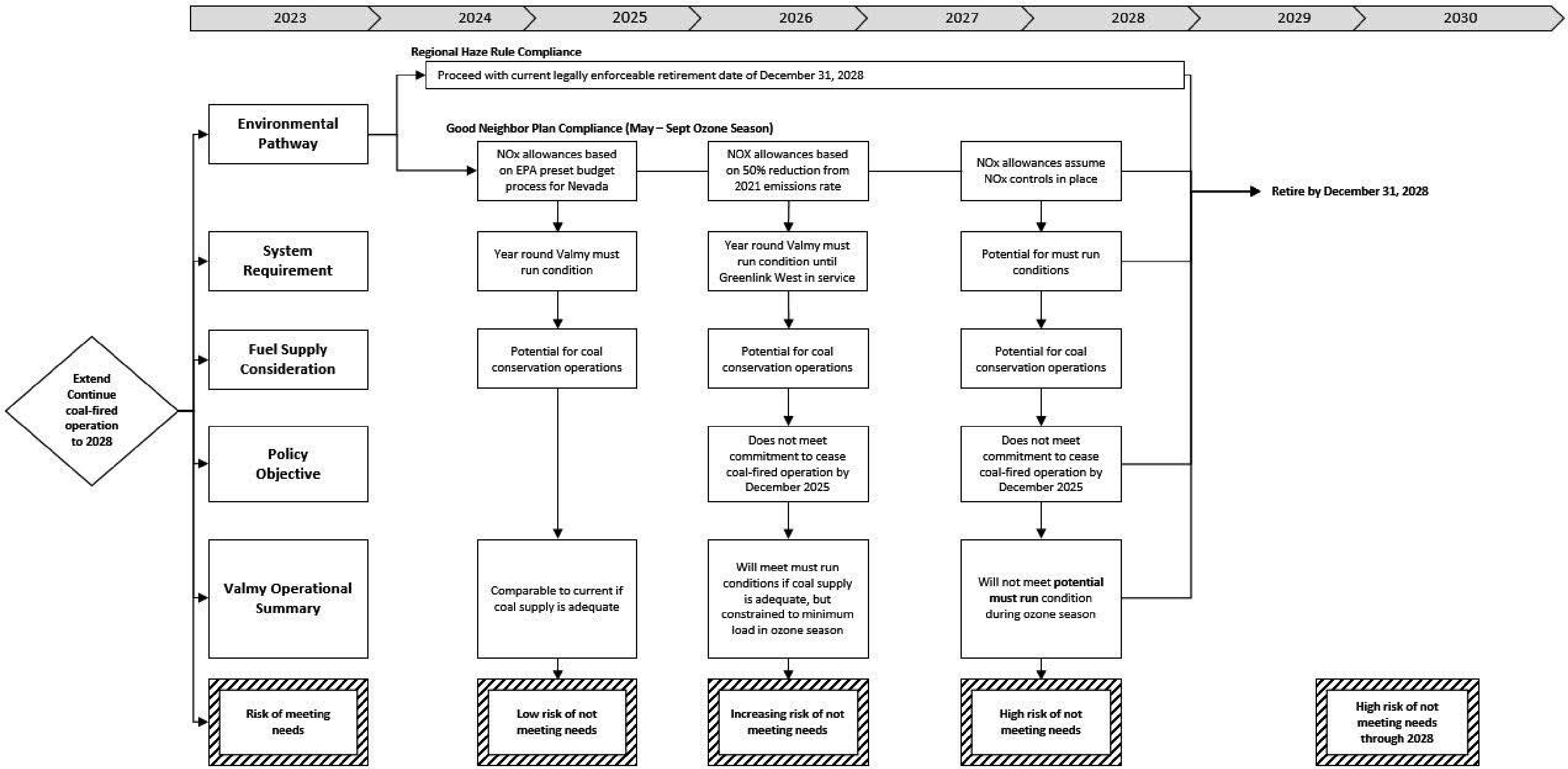


Key Considerations and Risks

A complete Valmy solution requires considerations in addition to the environmental regulations. For each Valmy solution pathway, separate figures were developed on the same timeline to incorporate key operational and policy considerations that impact decision making, including system requirements, reliability of fuel supply, policy objectives, and the ability to meet operational requirements. Based on these other considerations, potential risks to meet system needs at Valmy were identified. Figures GEN-2 through GEN-6 illustrate each Valmy pathway with these key considerations. The following observations were made for each Valmy solution pathway.

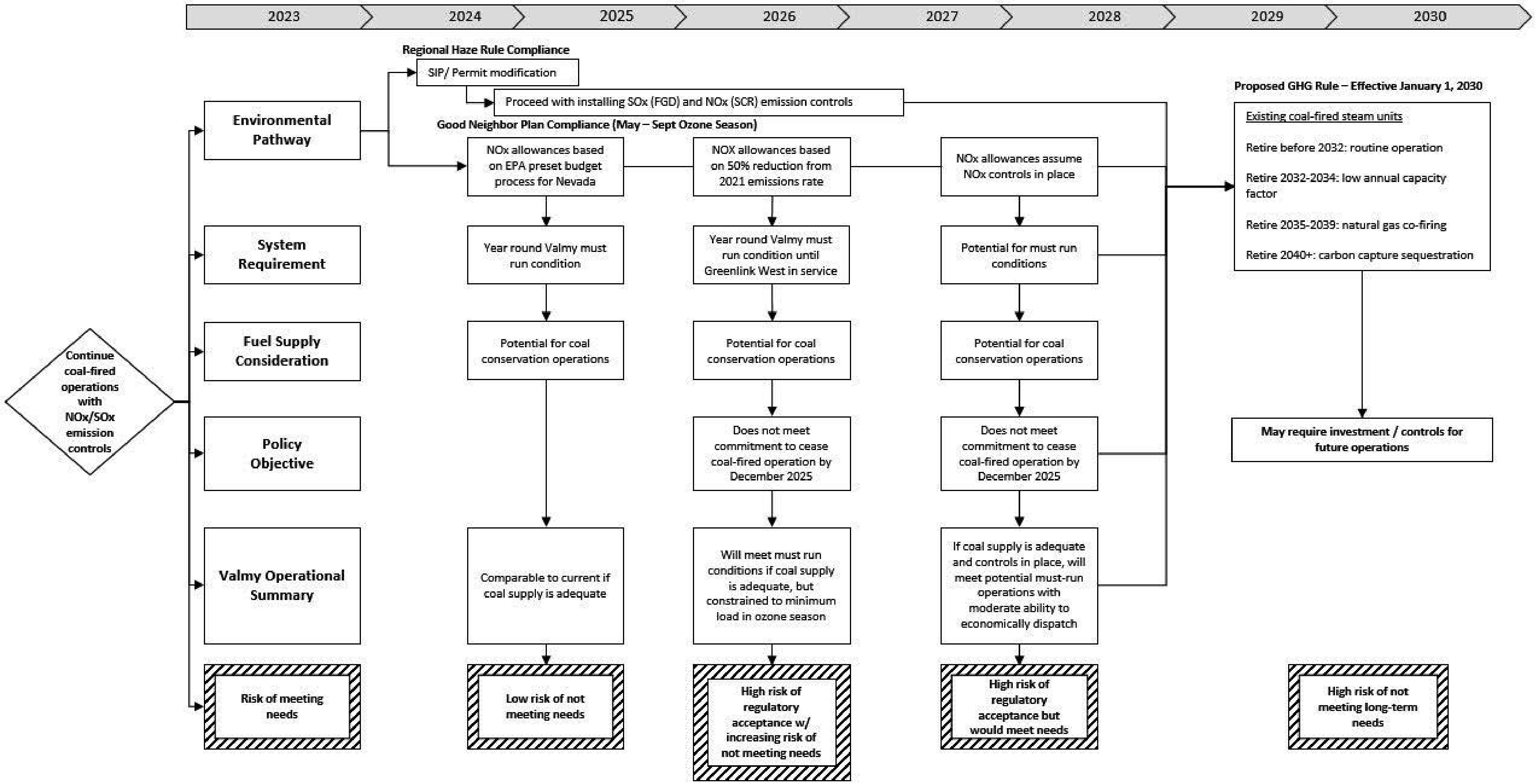
Extend coal-fired generation until 2028 (Figure GEN-2): In this pathway, system requirement risks increase in 2026 and are high starting in 2027 when operation during the ozone season would be constrained under the Good Neighbor Plan without NOx controls. The availability and transportation of a reliable coal supply creates some risk of meeting operational requirements if recent coal supply challenges persist. This option does not meet the December 2025 retirement date for coal-fired generation or advance carbon-reduction goals. Based on these considerations, operating Valmy as a coal-fired unit until 2028 results in a high risk of not meeting system needs.

FIGURE GEN-2
VALMY OPERATIONAL PATHWAYS – EXTEND COAL-FIRED OPERATION TO 2028



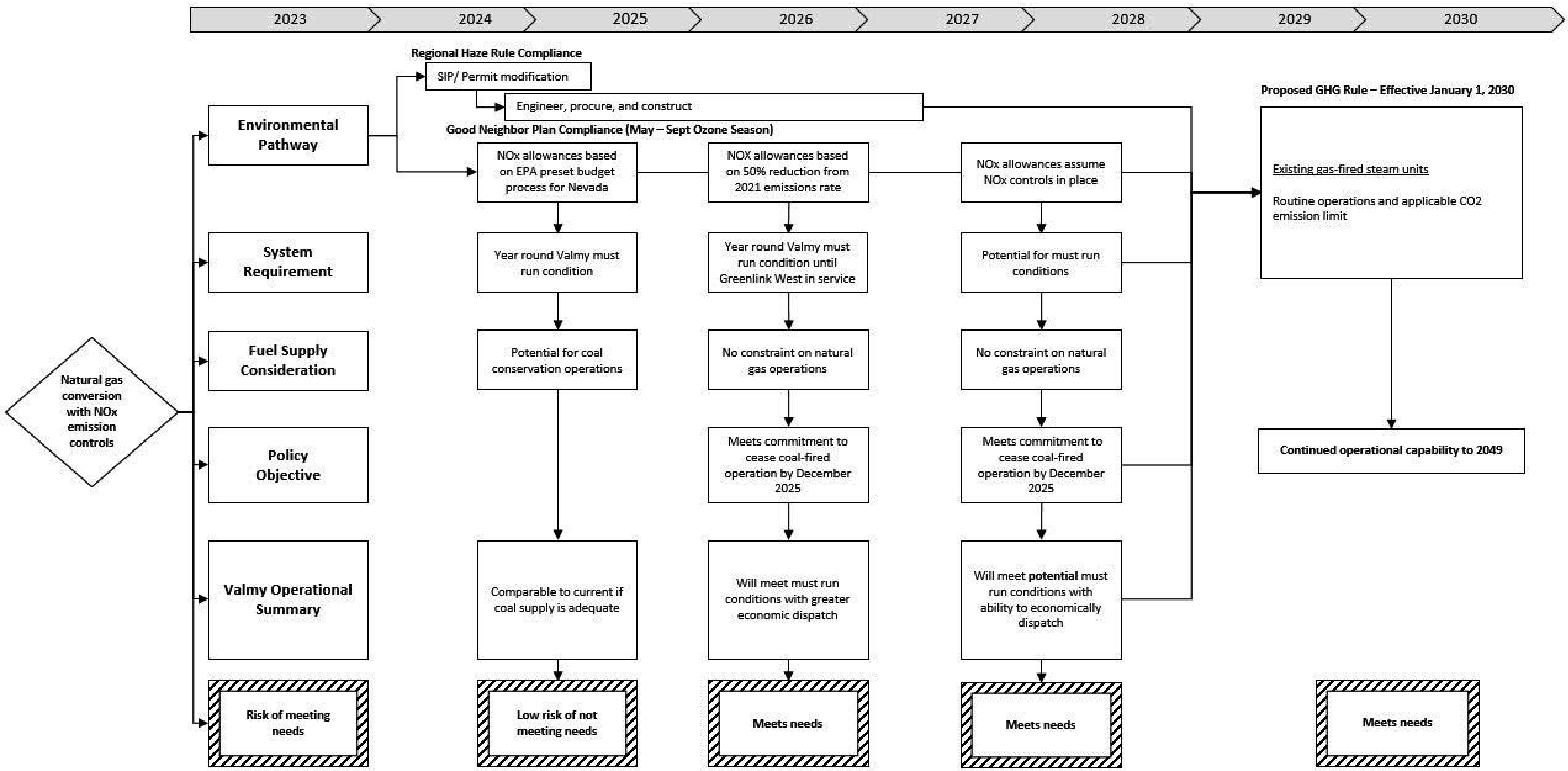
Continue coal-fired generation beyond 2028 (Figure GEN-3): If this pathway was successfully permitted, and emission controls installed before the 2027 ozone season, the Good Neighbor Plan and system requirements would be met. However, operation would be constrained in 2026 during the ozone season under the Good Neighbor Plan, limiting economic dispatch. In addition, future regulation, as illustrated by the proposed GHG rule, may require additional investment in emission controls to operate the units until 2049. The availability and transportation of a reliable coal supply creates some risk meeting operational requirements if recent coal supply challenges persist. This option does not meet the December 2025 retirement date for coal-fired generation or advance carbon-reduction goals. Based on these considerations, operating Valmy as a coal-fired unit beyond 2028 results in a high risk of not meeting long-term system needs.

FIGURE GEN-3
VALMY OPERATIONAL PATHWAYS – EXTEND COAL-FIRED OPERATION PAST 2028



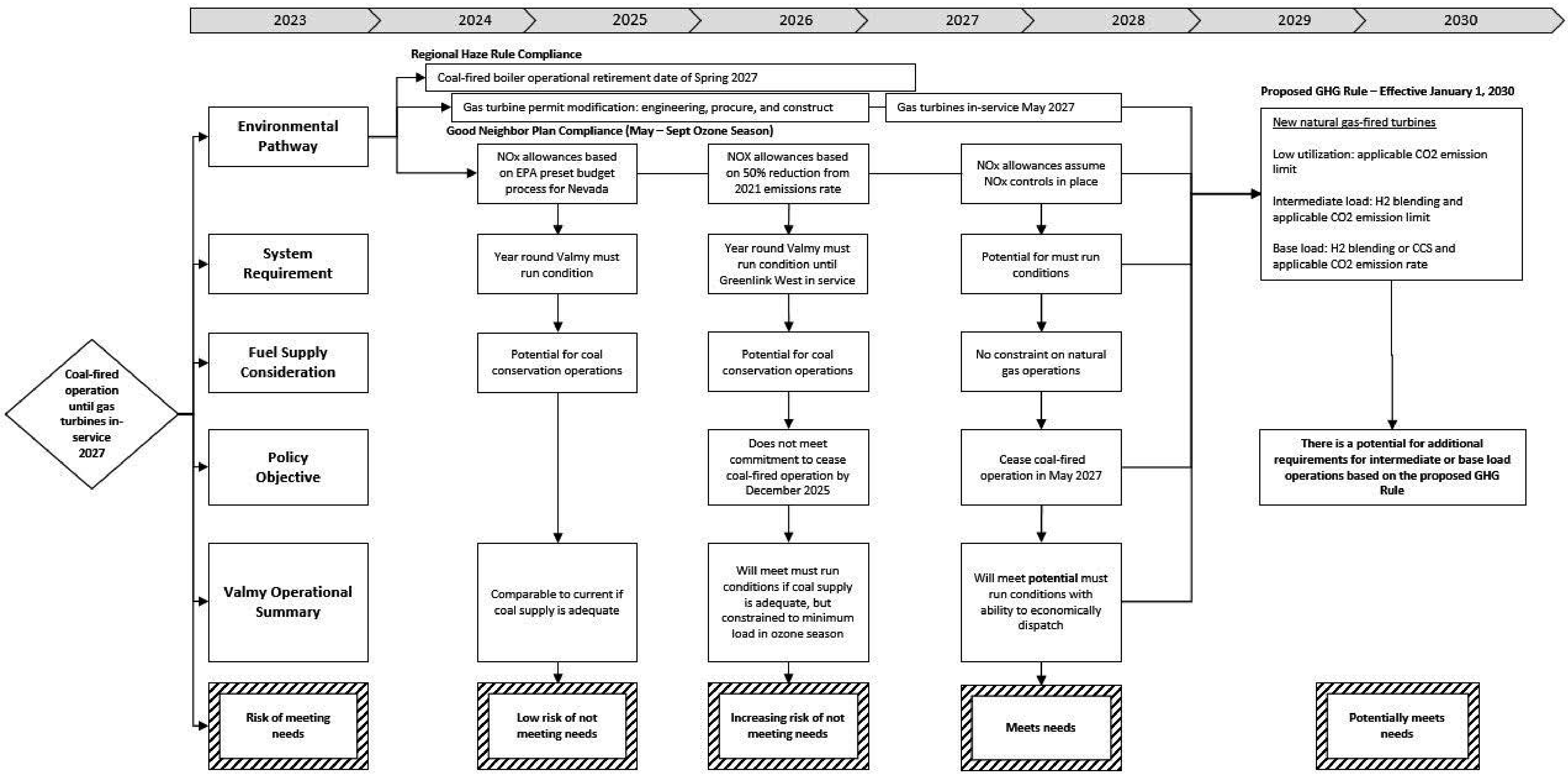
Natural gas conversion of existing units with NOx controls in 2026 (Figure GEN-4): Converting the Valmy units from coal-fired to natural gas generation is a feasible pathway that meets system needs and Good Neighbor Plan requirements as soon as the 2026 ozone season. The fuel conversion to natural gas mitigates the potential for future coal supply constraint impacts and phasing in the conversion of the two units may also allow cessation of coal-fired generation by December 2025. CO_2 emissions following the conversion are expected to meet the levels proposed in the GHG rule; therefore, the proposed GHG rule would not impede continued operation as a gas-fired steam unit through 2049. Based on these considerations, the pathway is a viable solution that would meet near-term and long-term needs.

FIGURE GEN-4
VALMY OPERATIONAL PATHWAYS – NATURAL GAS OPERATIONS EXTEND TO 2049



Replace existing units with new natural gas-fired turbines in 2027 (Figure GEN-5): Replacing the Valmy coal-fired units with new NOx emission controlled natural gas-fired generation is a feasible pathway that meets system needs and Good Neighbor Plan requirements by the 2027 ozone season. The change in fuel source to natural gas mitigates the potential impact of future coal supply constraints but does not meet the commitment to cease coal-fired generation by December 2025. Under the Good Neighbor Plan, coal-fired operation would be constrained in the 2026 ozone season, limiting economic dispatch. Future regulation under the proposed GHG rule may pose additional operating requirements starting 2030 if the new turbine units operate at levels greater than low utilization as determined by the state on a unit-specific basis if the rule were implemented. Based on these considerations, this pathway is a viable solution that would meet near-term needs with some future risk of additional requirements depending on future operation and regulation.

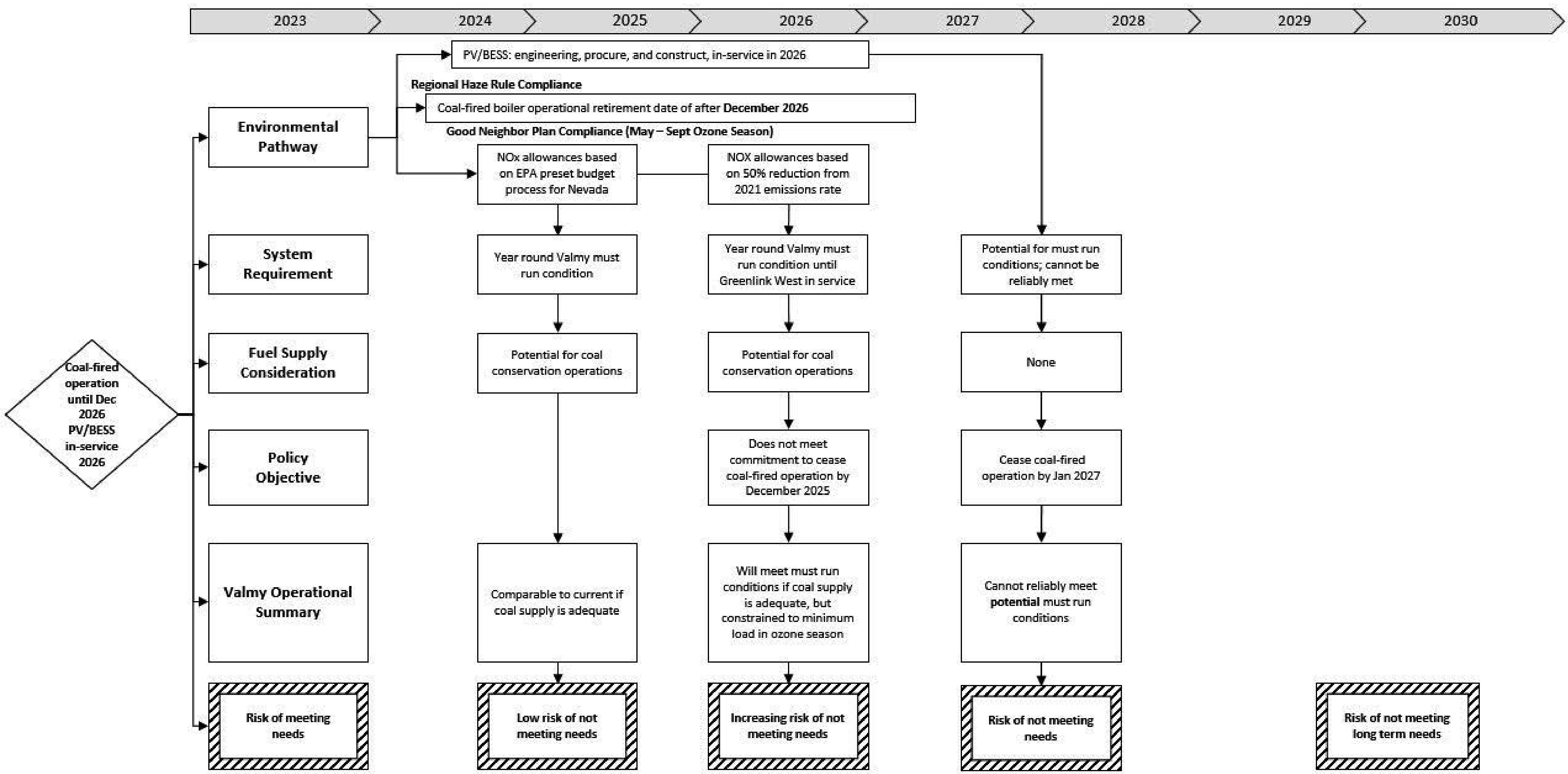
FIGURE GEN-5
VALMY OPERATIONAL PATHWAYS – NEW GAS TURBINES/ RETIRE COAL-FIRED UNITS 2027



Replace coal-fired generation with new PV/BESS (Figure GEN-6):

Replacing the Valmy coal-fired units with new PV/BESS would require continued must-run coal-fired operation until Greenlink West is in service at the end of 2026. Under the Good Neighbor Plan, coal-fired operation would be constrained in the 2026 ozone season, limiting economic dispatch. The coal fuel retirement mitigates the potential for future coal supply constraints after 2026 but does not meet the commitment to cease coal-fired generation by December 2025. However, the inability to meet potential around-the-clock generation requirements in the Valmy area after 2026 poses a risk since the PV/BESS alone do not provide a dispatchable 24/7 resource.

FIGURE GEN-6
VALMY OPERATIONAL PATHWAYS – NEW PV/BESS PROJECT/ RETIRE COAL-FIRED UNITS AFTER DEC 2026



Summary

Based on these pathway evaluations, the conversion of the Valmy units from coal to natural gas-fired or replacement with gas-fired turbines are both viable options. Continued operation of coal-fired generation until December 31, 2028, without NOx emission control does not appear to be a viable pathway. Similarly, continuing coal-fired generation beyond 2028 does not appear to be viable. The PV/BESS solution would not meet potential future around-the-clock generation needs as it does not provide a dispatchable 24/7 resource.

The Valmy LSAP presents evaluation of the two most viable pathways – repowering the Valmy units on natural gas and replacing the Valmy units with gas turbines. In addition, the option to replace the Valmy units with PV/BESS is presented for transparency despite potential future risks in this pathway.

E. Valmy Solution

The Valmy LSAP builds on the key considerations laid out previously, evaluating options to replace coal-fired combustion at Valmy. The Valmy LSAP considers repowering the existing Valmy units on natural gas with continued operation through 2049, replacement of the Valmy coal units with natural gas-fired peaking units, similar to the Silverhawk Peakers, and replacement with a PV/BESS resource. Economic analysis of these options is presented in the Economic Analysis Section and provided in Technical Appendix GEN-3.

A decision on a Valmy solution is essential at this time due to the limited time remaining until coal-fired operation is scheduled to cease and new environmental regulations restrict operation of the Valmy Units. For the natural gas conversion to be complete and coal-fired operation to cease by the end of 2025, the Engineering, Procurement and Construction ("EPC") contract will need to be issued immediately after the Commission order in this Docket. Alternately, to meet the 2027 Commercial Operation Date ("COD") of May 2027 for the simple-cycle combustion turbines, purchase of major equipment and issuing the EPC contract would need to be completed in the first quarter of 2024, immediately following a Commission order. Timely completion of either of these two viable Valmy solutions would require approval in this docket. The certainty of an order on the Valmy solution in this Docket will also provide the certainty needed for the permitting and modification to the SIP urgently necessary for the Valmy Solution gas conversion.

Based on all the considerations presented, the preferred solution for the Valmy units is conversion of the existing steam units to operate on natural gas and continued operation through 2049. The project to complete the conversion of the Valmy Units to operate on natural gas is described in the following subsection.

F. New Generation Projects

A. <u>Valmy Natural Gas Conversion</u>

<u>Project Overview</u>

Sierra is requesting approval to complete the conversion of the existing Valmy coal-fired Units 1 and 2 to operate on natural gas and complete the retirement of coal-fired operations at the Valmy Station. The project scope will include replacement of the coal-fired burner equipment on the existing boilers with burners and controls that will allow the units to operate on natural gas. Additionally, the conversion to natural gas is expected to require the installation of additional NOx controls such as SCR or SNCR. Finally, to prepare the units for long-term operation on natural gas, major outages would be completed on the units to bring all of the equipment to a state that would allow for continued operations.

The project and continued operation costs assumes that Idaho Power Company will continue to participate in the Valmy Station with its 50 percent ownership, sharing 50 percent of the output and cost. Discussion with Idaho Power Company indicates that they would participate in the conversion to natural gas and continue their 50 percent participation in the plant. Idaho Power Company is targeting a September 2023 IRP filing with their Commission.

The LSAP analysis is included in Technical Appendix GEN-3.

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

The project is also assumed to require the installation of SCR systems for the reduction of NOx emissions on both units.

<u>Idaho Power Company Participation</u>

Idaho Power Company is studying participation in the conversion of the Valmy units from coal to natural gas and has indicated its interest in participating in the conversion of both units at its 50 percent ownership share of the plant. Idaho Power Company expects to complete and file its resource plan filing in the fall of 2023. The Valmy natural gas conversion requested in this filing is for Sierra's share of the project with Idaho Power Company maintaining their 50 percent ownership and their share of the project costs and future output.

The LSAP also studied a scenario where Idaho Power Company does not participate in the coal to gas conversion and exits the Valmy Plant. In this scenario, Sierra completes the project at 100 percent of the cost and receives 100 percent of the output. The analysis shows that this scenario is cost effective for Sierra, but since Idaho Power Company has expressed interest in maintaining its interest and operation of its share, this alternative was not studied outside the LSAP.
If Idaho Power Company does not get approval for their share of the Valmy conversion and future participation in the plant, NV Energy will seek Commission approval to complete the full Valmy Repower, bear all associated costs, and receive the full capacity of both repowered Valmy units as described in Section 1 of this Amendment. To be clear, the current plant agreements with Idaho Power Company do not allow for this option and, consequently, this option is not being presented as one of the alternative plans.

NV Energy proposes to provide status updates and a potential compliance filing as described in Section 1 relative to Idaho Power Company's status in continuing ownership in the Valmy conversion.

Project Costs

The total cost of the Valmy conversion to natural gas is estimated at $165 million, with Sierra's 50 percent share being $82.6 million. The cost estimate includes capital improvements necessary for the continued operation of the Valmy units to prepare for operation from the current retirement date of 2025 through 2049. These capital improvements are further described in the LSAP.

TABLE GEN-3
VALMY COAL TO GAS CONVERSION
ESTIMATED ANNUAL CONSTRUCTION COSTS
IN $ MILLIONS, EXCLUDING AFUDC

Year	Total Project	Sierra's Share
2023	$0.5	$0.25
2024	$5	$2.5
2025	$64	$ 32
2026	$95.8	$ 47.9

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

	Total Project	**Sierra's Share**
EPC cost for natural gas conversion	[redacted]	[redacted]
Supply and installation of SCRs		
Capital projects for continued operation		
Total Installed Cost	$165,346,000	$82,682,000

These costs will be further defined as the Owner's Engineer is hired and detailed project costs are developed.

<u>Decommissioning of Coal and Coal Combustion Residuals Operations</u>

North Valmy's landfill is subject to the closure requirements in the federal Coal Combustion Residuals ("CCR") Rule. The landfill is also regulated by NDEP as a Class III landfill. The CCR Rule requires that closure must commence two years after the landfill received the last receipt of waste, either CCR or non-CCR waste, or two years after the last CCR was removed for beneficial use.[28] Based on this requirement and following prudent utility practices, retirement and decommissioning of facilities that handled coal, and ash residuals, or are no longer necessary to operate Valmy following conversion to natural gas operation will be completed such that the onsite landfill can be utilized for disposal, closed, and enter post-closure care monitoring under the CCR Rule and state permit requirements. These decommissioning and remediation costs were not analyzed in the LSAP as they would be incurred whether the plant was retired or converted to natural gas in the same time frame.

Prior to the natural gas conversion, a decommissioning plan will be developed to determine what areas can be de-energized, separated, decontaminated, demolished, and / or remediated. Planning will include a facility regulated materials survey, utility survey for re-routes or isolations, landfill survey and related activities to support planning and engineering. Facility-wide industrial cleaning will be completed to remove latent coal and ash, particularly in areas that were part of coal conveyance or ash conveyance systems. Any onsite disposal while the landfill is allowed to operate will help to diminish future costs for offsite disposal after the onsite landfill is closed. General areas expected to be part of this decommissioning include the coal yard area, coal conveyance systems, ash handling equipment, rail unloading areas (e.g., unloading trestle, thaw shed), and diesel start-up related storage and equipment. Soil or groundwater remediation may potentially be required in those areas where coal and diesel fuel were handled. Once these activities are complete,

[28] 40 CFR Section 257.102(e)(2).

the onsite landfill will be closed, and post-closure monitoring will commence per CCR regulations and state permit requirements.

The most recent decommissioning cost estimate was prepared for Valmy in 2018 and included in the 2022 Sierra electric depreciation filing (Docket No. 22-06015). Using this estimate as a basis for order of magnitude costs, it is expected that the cost to complete this partial decommissioning effort will range from $10 to $15 million total, with Sierra's share being 50 percent. A detailed estimate will be prepared as part of decommissioning planning. Post-closure landfill maintenance and monitoring and reporting will continue for a period of 30 years.

The costs for the retirement of coal operations at Valmy are not included in the project costs presented above and would be collected and recovered through a regulatory asset similar to the retirement of other coal facilities within the Companies' fleet. The undepreciated net book value for assets that are retired, and the related stranded inventory will also be included in the regulatory asset account.

Engineering and Design Development

As described in the LSAP, the project costs are based on the engineering study completed by Burns and McDonnell and the SCR costs are based on budgetary estimates provided by an SCR provider. As shown in the schedule that follows, Sierra intends to contract with an Owner's Engineer and complete the preliminary engineering and development of the Request for Proposal ("RFP") for the Engineering, Procurement and Construction ("EPC") in 2023.

Permits

As discussed in subsection B, Environmental Regulations Impacts, revision of the RHR SIP and Valmy Title V air permit modifications are being pursued in parallel with this filing. In the event the Valmy Natural Gas Conversion project is not approved by the Commission, the Companies anticipate that NDEP will re-file its RHR SIP revision and maintain the current Title V air permit with the legally enforceable retirement date of December 31, 2028.

Natural Gas Supply

The Valmy coal-to-gas conversion will require an interconnection to a new intrastate line in Humboldt County that will access supplies from the Ruby Pipeline. Pinyon Pipeline, LLC, a new pipeline affiliated with the Ruby Pipeline, has proposed a lateral that will supply natural gas to the Valmy Station to support this project. A proposed lateral and associated gas metering would be capable of delivering about 7,100 MMBtus hourly and 170,000 MMBtus daily, with guaranteed pressures of 650 psig and above.

Project Schedule

Table GEN-5 shows the preliminary project schedule for the Valmy Coal-to-Gas Conversion Project.

TABLE GEN-5
VALMY COAL-TO-GAS CONVERSION PROJECT SCHEDULE

Task Name	Start	Finish
NV Energy – Coal to Gas Conversion Project Schedule		
Owner's Engineer – RFP and Contracting	8/1/23	8/30/23
Develop Specification for EPC RFP Process	9/1/23	12/1/23
Complete EPC RFP Process	12/1/23	1/31/24
Issue notice to proceed for EPC contract	2/1/24	2/1/24
EPC Engineering	2/1/24	8/1/24
EPC Procurement	9/1/24	3/1/25
Contracting for Continuing Operations Capital Projects	2/1/24	9/1/24
PERMITTING		
Title V Air Permit	8/1/23	4/30/24
Modification of State Implementation Plan	8/1/23	12/31/24
OUTAGE AND CONSTRUCTION		
Unit 1 Outage and Construction	10/1/25	12/31/25
Unit 2 Outage and Construction	1/1/26	5/31/26

B. <u>Selective Catalytic Reduction Installation on Tracy Units 4/5</u>

Project Overview

As described in the LSAP included as Technical Appendix GEN-4, Sierra studied the continued operation of Tracy Units 4 and 5 beyond their current 2031 retirement date, through 2049. The LSAP determined it was economically prudent to continue operation of the units with the required installation of an SCR system. Operation beyond 2031 would also require capital investment for continued operation. These continued operation capital costs are further detailed in the LSAP. The analysis assumes that the SCR would be installed and operational in 2027. Although major project costs would not be incurred until after the Action Plan period of the 2021 IRP, Sierra is requesting approval of the permitting and analysis costs for the continued operation of the units, such that modification to the SIP and subsequent revisions to the Title V air permit can commence. The costs for the air permit modeling and analysis and preliminary engineering are expected to be approximately $200,000 during the remaining Action Plan Period.

Permits

As discussed in subsection B, Environmental Regulations Impacts, revisions of the RHR SIP and Tracy Units 4/5 Title V air permit are being pursued in parallel with this filing. In the event the continued operation of Tracy 4/5 is not approved by the Commission, the Companies anticipate NDEP will re-file the original SIP and maintain the current Title V air permit with the legally enforceable retirement date of December 31, 2031.

Project Costs

The total cost of the Tracy Units 4/5 SCR project is estimated at $53 million, without AFUDC. The project costs are estimated at this time since the engineering and design would not begin until after the permitting and modification to the SIP are completed. Much of the continuing operations capital was modeled to occur during a 2031 major outage on the unit, but these costs could be completed during an earlier outage if necessary.

TABLE GEN-6
TRACY 4/5 SCR PROJECT
ESTIMATED ANNUAL CONSTRUCTION COSTS
IN MILLIONS, EXCLUDING AFUDC

Year	Amount
2023	$ 0.5
2024	$ 1.5
2025	$ 2.5
2026	$ 3.0
2027	$ 6.0
2031	$40.0

TABLE GEN-7
TRACY 4/5 SCR PROJECT
ESTIMATED CONSTRUCTION COSTS BY MAJOR CATEGORY
(EXCLUDING AFUDC)
[REDACTED]

Permitting	[redacted]
Owner's Engineer and Construction Management	[redacted]
Supply and Installation for SCR Installation	[redacted]
Continuing Operations Capital	[redacted]
TOTAL INSTALLED COST	$53,500,000

Engineering and Design Development
Sierra has only completed high level budgetary estimates and studies at this time. Suppliers have indicated that the SCR system currently has a 18–24-month lead time. With a 2027 operation date, Sierra will begin engineering in 2025 following the permitting activities.

Schedule
Table GEN-8 shows the preliminary project schedule for the Tracy Units 4/5 SCR Project.

TABLE GEN-8
TRACY UNITS 4/5 SCR PROJECT SCHEDULE

Task Name	Start	Finish
PERMITTING		
Title V Air Permit	8/1/23	4/30/24
Modification of Regional Haze SIP	8/1/23	12/31/24
Owner's Engineer – RFP and Contracting	9/1/24	11/30/24
Develop Specification for EPC RFP Process	1/1/25	3/1/25
Complete EPC RFP Process	3/1/25	8/31/25
Issue notice to proceed for EPC contract	10/1/25	10/1/25
OUTAGE AND CONSTRUCTION		
SCR Installation Outage	10/1/27	12/31/27
Major Turbine Outage	1/1/31	5/31/31

C. VALMY SIMPLE-CYCLE PLANT

Project Overview
The Valmy Simple-Cycle Plant was analyzed as a new generation option. It is presented here to provide details used in modeling of one of the alternative plans. The Valmy simple cycle plant remains a viable option to the Valmy solution and based on other outside drivers may become the optimal solution if circumstances change. Sierra evaluated the construction of a simple-cycle peaking plant at the existing Valmy Station. The simple-cycle plant is made up of two 200 MW (nominal rating) simple-cycle generating units, designed for peaking service in Sierra's service territory. The estimated cost of the project is approximately $353 million (without AFUDC) or $883/kW.

The simple-cycle generating unit for the Valmy Simple-Cycle Plant is a highly efficient, state-of the-art, combustion turbine. To reduce emissions, a combination of dry low-NOx combustion systems, selective catalytic reduction and carbon monoxide catalyst will be incorporated into the design. The current project plan and pricing are based on a single GE 7FA.05 combustion turbine.

Information from the OEM for this unit states that the unit is capable of operating on a 15 percent hydrogen mixture, with the OEM planning a path towards allowing the unit to operate on 100 percent hydrogen. The simple cycle 7FA.05 gas turbine can reliably produce nearly 200 MW within 10 minutes and can reach full load in under 11 minutes. The unit can also balance renewable resources by load-following at 40 MW/min ramp rates while maintaining emissions compliance.

Natural Gas Supply

The Valmy Simple-Cycle Plant is expected to be interconnected to a new intrastate line in Humboldt County that will access supplies from the Ruby Pipeline. A proposed lateral and associated gas metering would be capable of delivering about 7,100 MMBtus hourly and 170,000 MMBtus daily, with guaranteed pressures of 650 psig and above. The lateral proposed for the Valmy coal-to-gas conversion described above would be capable of supplying the necessary natural gas for the simple-cycle plant operations. As with the project itself, approval of any upgrades to the lateral and metering is not being requested for approval in this filing.

Permits

Sierra has begun communications with the equipment manufacturer to obtain emission profiles for the selected combustion turbines to initiate air quality dispersion modeling and preparation for future permitting application with NDEP, if this project is pursued in the future. Standard permitting turnaround with NDEP can take 12-18 months after submittal of permit application.

Project Costs

The total cost of the Valmy Simple-Cycle Plant is approximately $353 million (without AFUDC), including projected pipeline and interconnection costs, or $883/kW. Table GEN-6 shows the construction costs by year and Table GEN-7 shows the line-item detail of the project cost. There is always a risk that material, equipment, and labor costs can increase or decrease between the time of the cost estimates and the time of contract award and procurement. Increases in construction costs in the past few years have been dramatic; however, Sierra has developed estimated costs for major contracts, based on costs seen for the Silverhawk Peaker Plant and believes that the costs to construct a Valmy Simple-Cycle Plant are accurately captured in this filing. Sierra has not made commitments for the turbines and generators.

TABLE GEN-9
VALMY SIMPLE-CYCLE PLANT
ESTIMATED ANNUAL CONSTRUCTION COSTS
MILLIONS, EXCLUDING AFUDC

Year	Amount
2024	
2025	$ 46.3
2026	$ 185
2027	$ 120.7

TABLE GEN-10
VALMY SIMPLE-CYCLE PLANT
ESTIMATED CONSTRUCTION COSTS BY MAJOR CATEGORY
(EXCLUDING AFUDC)
[REDACTED]

MAJOR EQUIPMENT SUPPLY	[redacted]	
BALANCE OF PLANT EQUIPMENT SUPPLY	[redacted]	
CIVIL/STRUCTURAL	[redacted]	
MECHANICAL INSTALLATION AND PIPING	[redacted]	
ELECTRICAL ASSEMBLY AND WIRING	[redacted]	
BUILDINGS	[redacted]	
ENGINEERING & STARTUP	[redacted]	
INDIRECT COSTS	[redacted]	[redacted]
CONTINGENCY	[redacted]	[redacted]
OVERHEAD (G&A) AND PROFIT	[redacted]	[redacted]
TOTAL EPC COSTS ($)	[redacted]	
OWNER'S COSTS	[redacted]	
TOTAL INSTALLED COST	$352,893,000	

Sierra has not spent or committed any significant expenditures on the Valmy Simple-Cycle Plant project and intends to limit expenditures unless the Commission approves a supply side plan which includes the Project.

Project Schedule

Table GEN-11 shows the preliminary project schedule for the Valmy Simple-Cycle Plant.

TABLE GEN-11
VALMY SIMPLE-CYCLE PLANT PROJECT SCHEDULE

Task Name	Start	Finish
NV Energy – Valmy Simple-Cycle Preliminary Project Schedule		
OWNER's ENGINEERING	09/1/2023	6/15/2027
Develop Specification for RFP Process	09/1/2023	12/31/2023
COMBUSTION TURBINE PROCUREMENT (GE7F.05s)	12/31/2023	3/31/2025
PERMITTING	01/1/2024	3/01/25
Title V Air Permit	02/1/2024	10/01/25
Secure PUCN IRP Amendment approval	03/6/2023	03/06/24
UEPA Permit	02/1/2024	3/01/25
LGIA Process - Studies and Approval	08/15/2023	10/01/24
Generator Step-up Transformers (GSUTs): Lead-time	09/01/23	12/01/24
GASLINE AND METERING STATION	02/01/24	03/01/25
ENGINEER-PROCURE-CONSTRUCT Contractor (EPC)	03/1/2024	5/31/2027
Switchyard Work	10/01/26	02/15/27
Construction	04/1/2025	03/29/27
Commissioning and Startup	03/01/27	05/31/27

SECTION 6. SUPPLY PLAN - RENEWABLES

A. Introduction

In this filing, the Companies seek approval for ongoing development and construction of a 400 MW solar and 400 MW Battery Energy Storage System ("BESS") project known as Sierra Solar and an asset purchase for future development of a 149 MW solar and 149 MW BESS project known as Crescent Valley Solar. This section also includes an information update for the right to lease the Amargosa Valley Solar Energy Zone. Sierra Solar and Crescent Valley Solar projects provide multiple benefits. First, these projects help close the Companies' open capacity positions and provide other benefits to the Companies' systems such as voltage support, load management and other system reliability benefits in a manner that enhances Nevada's energy independence. These two projects are capable of supplying energy after solar resources drop off in the evening hours.

Second, these projects allow the Companies to continue to meet the increasing Renewable Portfolio Standard ("RPS")[29] and the state's ambitious clean energy goals. The RPS is aggressively increasing, now requiring 50 percent renewable energy by 2030. Further, the state's 2050 clean energy goal targets an amount of energy production from zero carbon dioxide emission resources to match total electricity sales by 2050. The projects also take advantage of the newly available Production Tax Credit ("PTC") as well as the Investment Tax Credit ("ITC") for the solar and BESS, respectively.

Third, these projects will allow the Companies to meet current and future customer needs and support a growing need to provide customers with sustainable green energy, namely through the Nevada GreenEnergy Rider ("NGR") or Market Price Energy ("MPE") and Large Customer Market Price Energy ("LCMPE") programs. There is an increasing interest 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 and residential customers have their own sustainability objectives that may be more aggressive than the State's policies and having a robust, growing pool of renewable generators permits these programs to thrive.

Fourth, these projects provide a hedge against cancelations and delays of previously approved projects. In the past two years, several project developers have communicated difficulties in obtaining major equipment at acceptable costs to fulfill their contracted obligations. A number of the renewable resources, such as Southern Bighorn Solar, Chuckwalla Solar and Boulder Solar III, that are currently under development are facing delays, shortfalls, or cancelations due to the various market conditions surrounding the solar photovoltaic ("PV") and BESS markets. Delays, shortfalls,

[29] Any portfolio credits generated by these projects, not allocated per an Energy Supply Agreement ("ESA"), would contribute to RPS compliance.

or cancelations[30] of any renewable projects currently under development impede NV Energy's ability to meet the RPS. As a result of these concerns, the Companies present RPS forecast sensitivities based on reasonable assumptions of the expected real-life consequences of market impacts on the Companies' pipeline of approved projects in development. While the Companies cannot publicly speculate on the eventual fate of individual projects, it is reasonable and prudent to expect and plan for a portion of the projects to reach commercial operation late and for some to never reach commercial operation. Therefore, the Companies continue to bring forth additional renewable projects and continue to discuss other renewable procurement efforts aimed at providing solar PV and BESS project prices, delivery assurance, and ensuring a future pipeline of projects to bring forward for the Commission's consideration. The projects included in this filing are also self-developed or asset purchase resources for which the Companies manage the development milestones compared to reliance on unregulated developers.

Fifth, the Iron Point and Hot Pot solar PV/BESS projects approved in the 2021 Joint IRP, Docket No. 21-06003, are no longer being developed as previously planned. The developer failed to meet key project milestones and has provided the Companies with termination notices for the Build Transfer Agreements for both projects, to which the Companies have responded with their own notices of termination.

Sixth, the projects make efficient use of transmission investment dollars by locating new generation near new load which has become less common and more challenging as the Companies add renewable projects. Sierra Solar and Crescent Valley are located within Sierra's territory. The major transmission infrastructure addition required to serve this new load also allows these projects to deliver their energy and capacity to new customers in the load growth areas and other customers on the Sierra and Nevada Power systems.

Seventh, as self-developed projects, the Companies also target to avoid high developer cost premiums, as well as risk of developer termination agreements, while allowing the Companies to more fully control the use and reuse of the facility for future development phases. Additionally, the Companies' ownership will help to optimize utilization of the residual asset life after a typical 25-year contract term for similar assets. Sierra Solar is in the advanced development stage with site control, executed interconnection agreement, secured solar panel supply and project design, and permitting underway. Execution of Sierra Solar's Phase I at this time will also support efficient execution of future project phases at the same site. The Sierra Solar site will likely support expansion to 1,000 MW of solar with equivalent BESS capacity in subsequent phases of development.

Eighth, each of these projects is consistent with the goals of the recently passed Assembly Bill 524 ("AB 524") provisions related to the assurance of electric supply reliability, availability, and

[30] Iron Point and Hot Pot solar PV/BESS projects, approved in the 2021 Joint IRP (Docket No. 21-06003), have been canceled.

affordability, as well as commitments to the state's goals of reductions to greenhouse gas emissions and reducing reliance on power market purchases through securing energy from dedicated in-state resources while providing economic benefits to Nevadans. Sierra Solar is also the first solar and BESS project developed by the Companies in northern Nevada and will be the largest capacity solar plus storage resource operated by Sierra. In addition to the energy and capacity, customers will benefit from all associated environmental and renewable energy attributes as the solar plus storage will help reduce dependency on fossil-fueled generation. The project will also help Sierra improve its capacity position and provide some night-time renewable energy in support of the zero-carbon goals. The BESS portion of the project is also dispatchable and can provide a load-following capability. In addition, the Legislature established an aspirational goal of achieving by 2050 an amount of energy production from zero-carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service and the Sierra Solar project will help achieve that goal. Therefore, the Sierra Solar project supports state policy and is part of the critical infrastructure needed at this time.

Finally, the addition of these projects 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 renewable energy portfolios in the nation, including 21 geothermal projects, 34 solar projects and approximately a dozen of a mix of wind, biomass, hydro, and waste heat renewable energy projects active or under construction. The Companies' long-term goal of serving customers with 100 percent renewables has resulted in the approval of 4,263 MW of solar and 1,808 MW of battery storage. These efforts align with the Companies' ongoing commitment to support economic development throughout Nevada by collaborating with many partners to attract, retain, and expand industry to diversify the economy. When a portion of the renewable energy is allocated to specific job-generating customers, it also promotes overall economic development, creates additional tax base for the state and counties, and lowers the total amount of energy that otherwise would have to come from carbon-based generating resources. This benefits the environment and the citizens of the state as a whole and aligns with the state's overall policy goals.

B. Renewable Energy Plan (Renewable Energy Resources)

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 Annual RPS Compliance filing, Docket No. 23-04011, Nevada Power and Sierra both exceeded their respective 2022 RPS credit requirements of 29 percent. Nevada Power ended 2022 at 37.1 percent, a record for Nevada Power, while Sierra ended 2022 with 35.8 percent. Adding to Sierra's renewable capacity, North Valley geothermal, a 25 MW facility, declared commercial operation on April 26, 2023, and was not included in the 2022 percentages above. In May 2023, a new Nevada Power renewable facility, Eagle Shadow Mountain, a 300 MW solar facility, declared commercial operation. Both facilities will increase the total amount of renewable energy and associated portfolio credits ("PCs") available to meet the energy needs of Sierra's and Nevada Power's customers.

As of May 31, 2023, Nevada Power had approximately 1,870 MW of renewable generating resources providing renewable energy to meet the energy needs of its customers.[31] In addition, Nevada Power ended May 2023 with four active solar PV projects in various stages of development, construction, and testing, totaling an additional 1,028 MW of new generation.[32] All four of these 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. Note the planned CODs for both Moapa and Boulder Solar III have been updated to reflect delays in the project schedule as communicated by the respective developers.

TABLE REN-1 NEVADA POWER PIPELINE RENEWABLE GENERATION

	Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	Energy / Capacity Allocation	
							NPC	SPPC
1	Moapa (Arrow Canyon) Solar [a, b.]	Solar PV	19-06039	08/16/23	200	75	**60**	140
2	Dry Lake	Solar PV	20-07023	12/31/23	150	100	**150**	
3	Gemini Solar [c.]	Solar PV	19-06039	05/01/24	690	380	**690**	
4	Boulder Solar III	Solar PV	20-07023	06/01/25	128	58	**128**	
					1,168	613	**1,028**	140.0

Notes to Table REN-1

a. Moapa began delivering test energy in 2022.

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

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

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

[32] The 1,028 divides the capacity of Moapa (NPC 60 MW, SPPC 140 MW) based on the Commission's order approving the project.

As of May 31, 2023, Sierra had approximately 965.9 MW of renewable generating resources providing renewable energy to meet the energy needs of its customers.[33] In addition, Sierra ended May 2023 with one solar PV and nine geothermal projects in various stages of development, construction, and testing totaling an additional 280 MW of new generation. The solar project includes a 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.

TABLE REN-2 SIERRA PIPELINE GENERATION

							Energy / Capacity Allocation	
	Facility	Resource Type	Approval Docket No.	Projected COD	Nameplate MW AC	Storage Capacity	**SPPC**	NPC
1	Moapa (Arrow Canyon) Solar [a., b.]	Solar PV	19-06039	08/16/23	200	75	**140**	60
2	Ormat Portfolio (OWGP, LLC)							
	> Beowawe	Geothermal	22-11032	01/01/25	20		**20**	
	> Galena 1	Geothermal	22-11032	02/01/27	15		**15**	
	> Desert Peak 2	Geothermal	22-11032	02/01/28	10		**10**	
	> Galena 3	Geothermal	22-11032	01/01/29	15		**15**	
	> North Valley 2	Geothermal	22-11032	01/01/26	15		**15**	
	> Lone Mountain	Geothermal	22-11032	01/01/26	15		**15**	
	> Gerlach	Geothermal	22-11032	01/01/28	15		**15**	
	> Pinto	Geothermal	22-11032	01/01/27	15		**15**	
3	Valmy (Eavor) Geothermal [c.]	Geothermal	22-11032	12/31/26	20		**20**	
					340	0	**280**	60.0

Notes to Table REN-2

a. Moapa began delivering test energy in 2022.

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

c. Valmy Geothermal will power up in phases with initial deliveries starting November 2025 and full operations expected by December 2028.

Tables REN-1 and REN-2 no longer include Chuckwalla Solar (solar PV 200 MW and 75 MW BESS) and Southern Bighorn Solar (solar PV 300 MW and 135 MW BESS). The developers of Chuckwalla and Southern Bighorn Solar have indicated they will not complete the projects as contracted and parties are negotiating the termination of the power purchase agreements. Parties are also negotiating with the potential to revive the projects and, if successful, the Companies will bring the projects forward in a future filing. Additionally, there is no change in the planning forecast from what was stated in the Fourth Amendment regarding the Hot Pot (solar PV 350 MW) and Iron Point (solar PV 250 MW) projects. The developer of Iron Point and Hot Pot, which were approved

[33] The 965.9 MW total divides the Nevada Solar One 69 MW agreement between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission. It also includes two small hydro projects, Kingston (.16 MW) and Mill Creek (.04 MW) as well on the credit only agreement with Truckee Meadows Waste Water (.80 MW), but it excludes Hooper Hydro (.8 MW) where Sierra does not claim the PCs from the generation and RO Ranch Hydro (.225 MW) which was shuttered but the PPA remains active.

in Docket No. 21-06001, has provided the Companies with termination notices of Build-Transfer Agreements for both projects, to which the Companies have responded with their own notices of termination. Therefore, these projects will not reach their planned commercial operation dates and are no longer included in the pipeline. Because the Commission's order approving the projects divided the energy between Nevada Power and Sierra, the loss of these projects impacts both utilities.[34]

The following is a summary of Nevada Power's and Sierra's portfolios of renewable facilities that contributed to Nevada Power and Sierra meeting the RPS requirements as of May 31, 2023. The list below does not include the Mojave community based solar project, short-term agreements, Nevada Power's allocation of Hoover, or projects that are dedicated to supporting commitments to meet customer-specific requirements for renewable energy under a Commission approved, NGR Option 2 tariff.[35] The Companies made a separate compliance filing required by Schedule No. NGR in Docket No. 23-03029.

NEVADA POWER

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

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

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

[34] Southern Bighorn was split 120 MW Sierra and 180 MW Nevada Power, Iron Point was split 110 MW Sierra and 140 MW Nevada Power; Hot Pot was split 154 MW Sierra and 196 MW Nevada Power.
[35] Nevada Power entered into a short-term purchase agreement with Tonopah Solar Energy for the output of the Crescent Dunes Solar Thermal Plant for the period December 21, 2021, through September 30, 2024, which is not expected to impact the Companies' RPS compliance outlook. The 0.350-MW Mojave project reached commercial operation in December of 2021 and its contribution to the RPS compliance outlook is negligible. Facilities entirely dedicated to NGR customers are Boulder Solar II, Switch Station 1, Switch Station 2, Techren Solar 2 and Turquoise Nevada.

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 facility began producing energy in 2012. The PPA terminates on December 31, 2037.

10. Boulder Solar I

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

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

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

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

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

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

18. <u>Stillwater 2 Solar</u>
The Stillwater 2 Solar facility is a 22 MW solar PV project located in Washoe County,

Nevada. The project was approved by the Commission in 2011. The solar array began producing energy in 2012. The PPA terminates on December 31, 2029.

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

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

21. Arrow Canyon Solar
Arrow Canyon Solar, formerly Moapa Solar, is a 200 MW solar PV facility with 75 MW of BESS capacity that will be located on the Moapa River Indian Reservation north of Las Vegas, Nevada. The solar array was projected to declare commercial operations in December 2022 but has been delayed due to difficulty in obtaining BESS equipment. However, the site has been providing energy and PCs since September 26, 2022. The project, including the BESS, is expected to achieve commercial operation August 16, 2023. The energy, capacity and PCs generated by the facility will be split 70 percent to Sierra, 30 percent to Nevada Power. The 25-year PPA was approved by the Commission in Docket No. 19-06039.

22. 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 facility was projected to declare commercial operations in September 2023; however due to the developer's failure to meet critical project milestones, the Companies anticipate the project will not reach commercial operation. The energy, capacity and PCs generated by the facility were to 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. 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.

28. Apex Landfill Facility

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

29. Lockwood Renewable Energy Facility

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

30. Goodsprings Recovered Energy Generation Station

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

31. Dry Lake Solar

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

32. Chuckwalla Solar

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 facility was projected to declare commercial operations in December 2023; however due to the developer's failure to meet critical project milestones, the companies anticipate the project will not reach commercial operation. The 22-year PPA was approved by the Commission in Docket No. 20-07023.

33. Boulder Solar III

The Boulder Solar III project is a 128 MW solar PV facility with 58 MW of BESS capacity located in Boulder City, Nevada. The facility was originally projected to declare commercial operations in December 2023; however, the developer has experienced a variety of project delays and is now projecting a COD of June 1, 2025. The 12-year PPA was approved by the Commission in Docket No. 20-07023.

SIERRA

1. Beowawe Geothermal Power Plant

The Beowawe facility is a 17.7 MW geothermal facility located in Eureka County and is owned by Terra-Gen Power. The plant was placed into service in 1985 and was originally under contract with Southern California Edison. However, in 2006, Sierra entered into a contract for renewable energy that expires on December 31, 2024.

2. Burdette Geothermal Power Plant

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

3. Galena 3 Geothermal Power Plant

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

4. North Valley Geothermal

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

5. 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 had a 30-year PPA with the facility that expired on November 30, 2022. The Company attempted to extend the PPA but was informed by the counterparty that a PPA extension was not available.

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 had a 30-year PPA with the facility that expired on November 30, 2022. The Company attempted to extend the PPA but was informed by the counterparty that a PPA extension was not available.

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 farm declared commercial operation on March 2, 2022. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

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 declared commercial operation on March 15, 2022. The project was approved by the Commission in Docket No. 18-06003. The PPA is for 25 years.

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. Fleish Hydro Power Plant

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.

14. New Lahontan Truckee Carson Irrigation District Hydro Power Plant

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.

15. Verdi Hydro Power Plant

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.

16. Washoe Hydro Power Plant

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

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

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

18. Kingston Hydro

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

19. <u>Mill Creek Hydro</u>

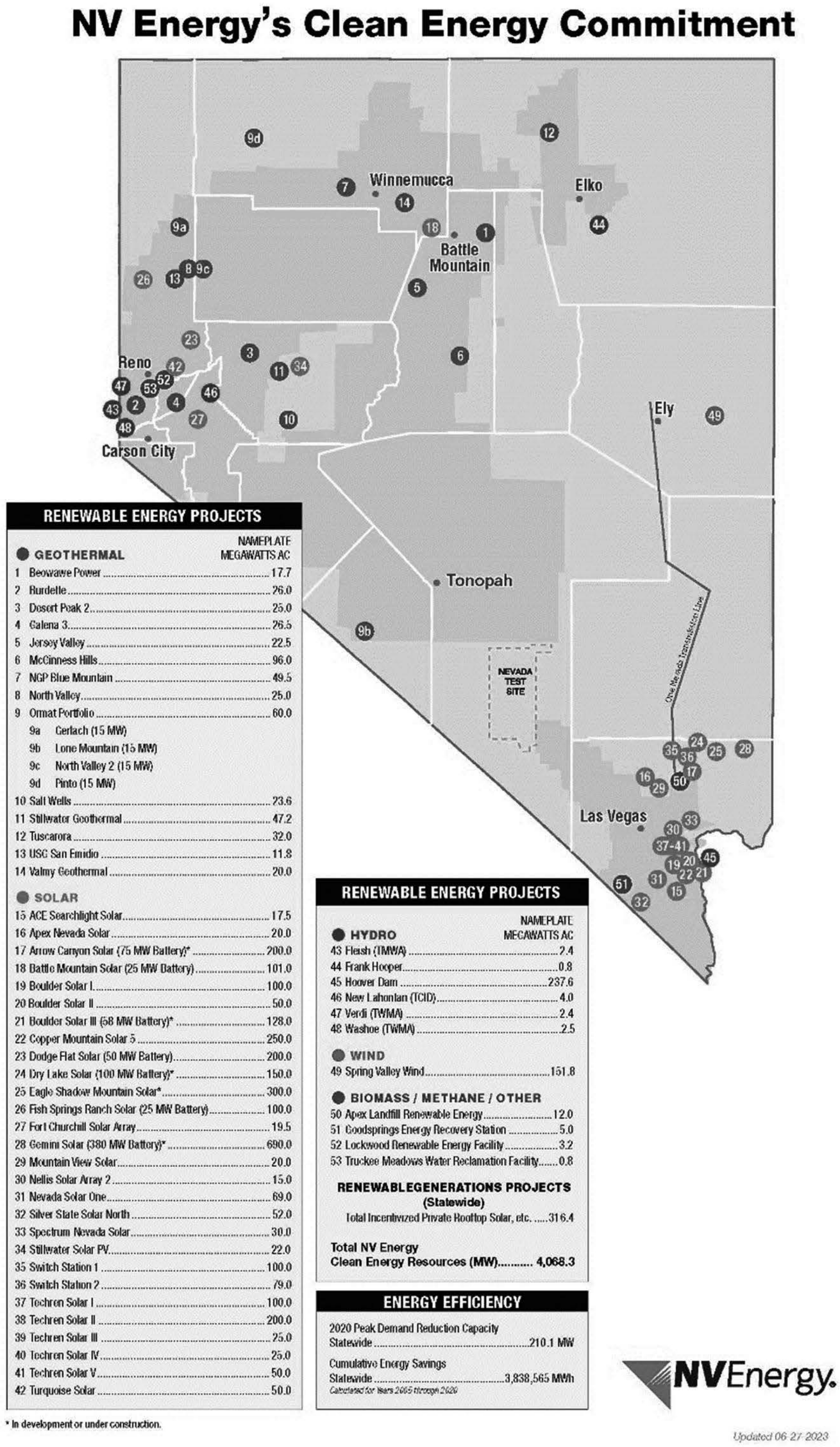
Mill Creek Hydro is a small, 0.037 MW, hydro facility located in Elko County, Nevada. It is owned by Van Norman Ranches, LLC. The facility received a rebate under Sierra's Hydro Demonstration Program. Under the demonstration program the rights to the PCs are assigned to Sierra. The PCs from this facility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

20. <u>RO Ranch Hydro</u>

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

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

FIGURE REN-1 RENEWABLE ENERGY MAP



C. Compliance Outlook

Nevada Power and Sierra both exceeded the 2022 RPS requirement of 29 percent. They are also expected to exceed the 2023 RPS requirement of 29 percent when the Companies report 2023 results in April 2024. Nevada's RPS is a credit requirement calculated based on total retail megawatt hour sales. Under current law, the RPS increases to 34 percent in 2024, 42 percent in 2027, and 50 percent in 2030 and beyond.[36] The current RPS rules permit utilities to exclude from the RPS calculation retail sales that are covered under a green energy tariff pursuant to NRS 704.738. The rules also permit the use of PCs from large hydro facilities, such as Hoover Dam.

The RPS includes 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[37] 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.

<u>NEVADA POWER</u>

Nevada Power's RPS compliance outlook is cautious. While the Company has been successful in building a pipeline of new projects to meet its future credit and renewable energy needs, no project pipeline is without risk. The biggest challenges continue to be delays and cancelations by project developers. For example, the Southern Bighorn Solar and Chuckwalla Solar projects failed to meet critical project milestones and will likely not move forward. Therefore, Southern Bighorn Solar and Chuckwalla Solar have been removed from the current project pipeline. Moreover, both Iron Point, a 250-MW solar facility originally scheduled to declare commercial operation in December 2023, and Hot Pot, a 350-MW solar facility originally scheduled to declare commercial operation in December 2024, have been effectively canceled. Both projects failed to achieve development milestones that impacted the ability of the projects to meet their contractual cost and operational commitments. Valmy BESS discussion in the Origination/Renewable Energy section below provides additional detail regarding the Iron Point and Hot Pot project status and the developer's bid in the 2023 Open Resource Request for Proposal.

Currently, all of Nevada Power's pipeline projects are solar, and the difficulty of procuring panels, racking, cabling, transformers, and other critical hardware is not unique to any single project. Supply chain disruptions and restrictions are now part of doing business in a post-COVID world, and it is possible that additional pipeline projects may experience similar delays.[38] With the loss of

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[36] NRS 704.7821.

[37] 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.

[38] Delays are an evolving challenge and both utilities will continue to adjust their outlooks and take corrective action as new information and alternatives become available.

Southern Big Horn and Chuckwalla, Nevada Power does not have sufficient current and pipeline capacity to absorb additional energy/credit losses stemming from delays and/or terminations. Supply chain delays and shortages can drive up costs to a point where a project that was previously economic becomes uneconomic. Unlike delayed projects where a project might be able to deliver test energy during a protracted construction/commissioning process, canceled projects deliver nothing and can take four or more years, from start of procurement efforts to COD, to replace. Nevada Power is working closely with its counterparties to monitor the status of projects under development/construction, and it will consider all options to cure should a counterparty fail to meet its project milestones as defined in the PPA.

In summary, while Nevada Power is currently positioned to meet its future credit commitments (RPS, NGR, ESA and 704B obligations) in the short term, experience has shown that renewable projects, both operating and pipeline, are unpredictable. Nevada Power will continue to explore all options, including continuing to issue renewable energy RFPs, self-developing projects, conducting bi-lateral asset purchase and other commercial transactions and exploring short-term purchase agreements that benefit customers, so that it can procure the renewable generating resources needed to continue its commitment to becoming carbon-free. To this end, RPS is the floor.

SIERRA

Sierra's RPS compliance outlook is positive. This is an upgrade from 2022's outlook of cautiously optimistic for several reasons: 1) two new large solar projects, Dodge Flat and Fish Springs Ranch, described earlier in this filing achieved COD in 2022; 2) Sierra's latest geothermal project, North Valley geothermal, achieved COD in April 2023; and 3) the Commission approved the Ormat Portfolio PPA and Eavor (Valmy) geothermal PPA in Docket No. 22-11032. Although no outlook is without risk, Sierra currently does not face the same degree of uncertainty as Nevada Power. This outlook is subject to change based on future load forecast updates. Sierra only has one solar project in its pipeline, Moapa Arrow Canyon Solar, and that project is nearing commercial operation. In addition, four of the eight geothermal projects that are part of the Ormat portfolio agreement are existing projects, so the risk that the geothermal resource is unable to support the contracted capacity is low. Finally, while both utilities continue to focus on building a robust portfolio of renewable generation to meet a growing RPS and customer demand, Sierra has been especially successful in its efforts to replace generation lost to expiring PPAs.[39] Specifically, the Ormat portfolio agreement approved in Docket No. 22-11032 makes a significant impact in helping to backfill geothermal energy lost due to expiring geothermal PPAs.

In summary, while Sierra is currently positioned to meet its future credit commitments (RPS and

[39] This does not imply that the Companies would rule out renewing existing agreements. Rather, it recognizes the uncertainty as to whether the resource and equipment are capable of supporting ongoing generation, and whether the Companies and the counterparty can come to terms on renewing the agreement. In 2022, three geothermal PPAs expired: Brady, Steamboat 2, and Steamboat 3.

NGR obligations) in the short term, experience has shown that renewable projects, both operating and pipeline, are unpredictable. To this end, Sierra will continue to explore all options like those stated for Nevada Power above so that it can procure the renewable generating resources it needs to continue its goal to becoming carbon-free. Again, to this end, the RPS is the floor.

Renewable Energy Planning

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

- Full compliance with an escalating and compressed RPS schedule: 34 percent by 2024, 42 percent by 2027, and 50 percent by 2030;
- Ensuring enough renewable capacity to satisfy a strong and growing demand from the Nevada business community to meet their energy needs from carbon-free, sustainable energy; and
- Developing a long-term strategy to build a generating portfolio that is capable of progressing towards the Nevada policy goal of delivering 100 percent carbon-free energy to all customers by 2050.

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

- Existing PPAs expire in accordance with the contract terms and are not automatically renewed;[40]
- The Companies adjusted the expected amount of energy and PCs from renewable facilities for the period of 2023-2026 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 Integrated Resource Plans ("IRPs") and Energy Supply Plans ("ESPs").

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

This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-term plans;

- The projected number of PCs derived from the Renewable Generations incentive programs plateaued in 2020 with the last of the incentivized solar systems now installed. Starting in 2021, the expected number of credits from incentivized rooftop solar is forecasted to begin decreasing by 0.5 percent per year as these systems age and their output slowly begins to decline;[41]
- 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 DSM measures are limited to no more than 10 percent of the credit total for 2021 through 2024 before dropping to zero effective 2025. The plan also assumes, based on current DSM kPC projections, that Sierra may not have a sufficient number of DSM PCs to completely fill the 10 percent cap in 2024;

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

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

- The plan accounts for all Commission approved and existing NGR and ESAs as of May 31, 2023, where PCs associated with all or a portion of the output from a renewable facility(ies) has been assigned to a customer under the NGR, the 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;

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

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

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

- The base plan includes the Ormat Portfolio PPA which consists of eight geothermal plants totaling 120 MW with staggered COD dates, and the 20 MW Valmy (Eavor) Geothermal PPA. Sierra will be the sole off taker of the energy and PCs from both agreements. The two PPAs were approved by the Commission in Docket No. 22-11032. The total number of PCs for the Ormat Portfolio PPA includes estimated station usage PCs. Certain geothermal station usage, the energy for the extraction and transportation of geothermal brine or used to pump or compress geothermal brine, is eligible for certification under the NRS § 704.78215(3)(b). Station usage PCs for this facility were estimated at 15 percent of net;

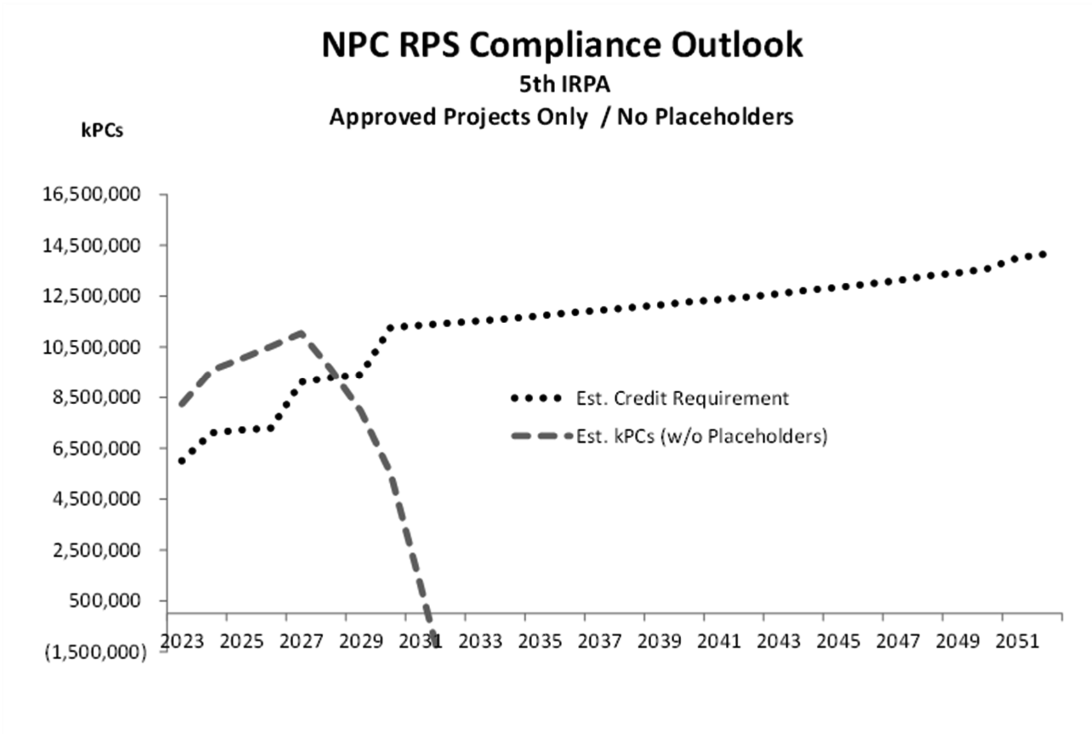
- The annual amount of energy produced by solar PV systems paired with BESS has been reduced to account for battery losses. The adjustment recognized that not all of the energy produced by PV arrays paired with energy storage will be delivered real-time to the grid. Some of the energy will be stored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

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

The following Figures 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 – neither the ones requested for approval in this Amendment nor placeholders. Both figures are based on each Company's current renewable portfolio, viable pipeline projects, and above planning protocol under a base load projection.[42]

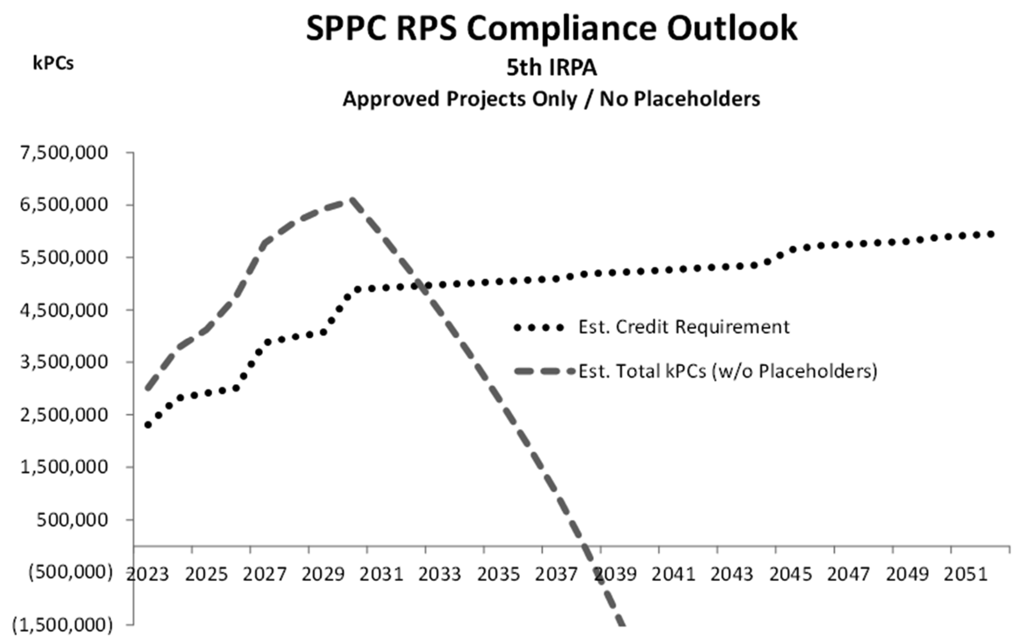
[42] Reference Tables REN-1 and REN-2 above for a list of active pipeline projects.

FIGURE REN-2 NEVADA POWER RPS OUTLOOK APPROVED PROJECTS ONLY



Based on the above, Nevada Power is projected to be RPS non-compliant in 2029.

FIGURE REN-3 SIERRA RPS OUTLOOK APPROVED PROJECTS ONLY



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

The next set of figures illustrates the preferred plan. The preferred plan assumes the approval of Sierra Solar coupled with PLEXOS-generated renewable placeholders to construct a least-cost plan showing the timing and capacity of new renewable resources needed for both utilities to maintain RPS compliance and collectively ramp up capacity to be able to generate enough renewable energy to offset one hundred percent of the Companies' total bundled retail electrical sales by 2050. The preferred plan assumes that the energy and credits from Sierra Solar would be split 60 percent Nevada Power, 40 percent Sierra. This buildout is based on the data available today.[43] The timing and type of placeholder projects submitted for Commission approval over the next thirty years will be driven by the Companies' energy and capacity needs, relevant federal and state statutes, the renewable and storage technology available, and the proposals submitted in response to RFPs issued. The associated number of PCs is shown in the charts below on a secondary axis. As renewable generation reaches and exceeds 50 percent of retail sales, the associated number of PCs will grow exponentially due to credit banking.

Figure REN-4 shows the compliance outlook for Nevada Power given the above assumptions. The chart shows the impact of taking no action which will result in future non-compliance and a failure to achieve the one hundred percent goal by 2050. The chart also shows the outlook under the preferred plan, a scenario whereby both utilities grow renewable capacity by adding new renewable

[43] While not reflected in the preferred plan figures, the Nevada Power has a pending ESA with MSG Las Vegas, LLC that would use Sierra Solar capacity.

resources, such as Sierra Solar, to achieve the goal to provide one hundred percent renewable generation to their customers. As noted in the data tables included in Technical Appendix REN-2, the projected number of renewable credits under the preferred plan is charted on the right axis in Figure REN-4. This is due to the impact of credit banking. The number of RPS eligible credits will increase significantly once the overall percentage of energy supplied by renewable generation exceeds the 50 percent threshold.

FIGURE REN-4 NEVADA POWER RPS OUTLOOK PREFERRED PLAN

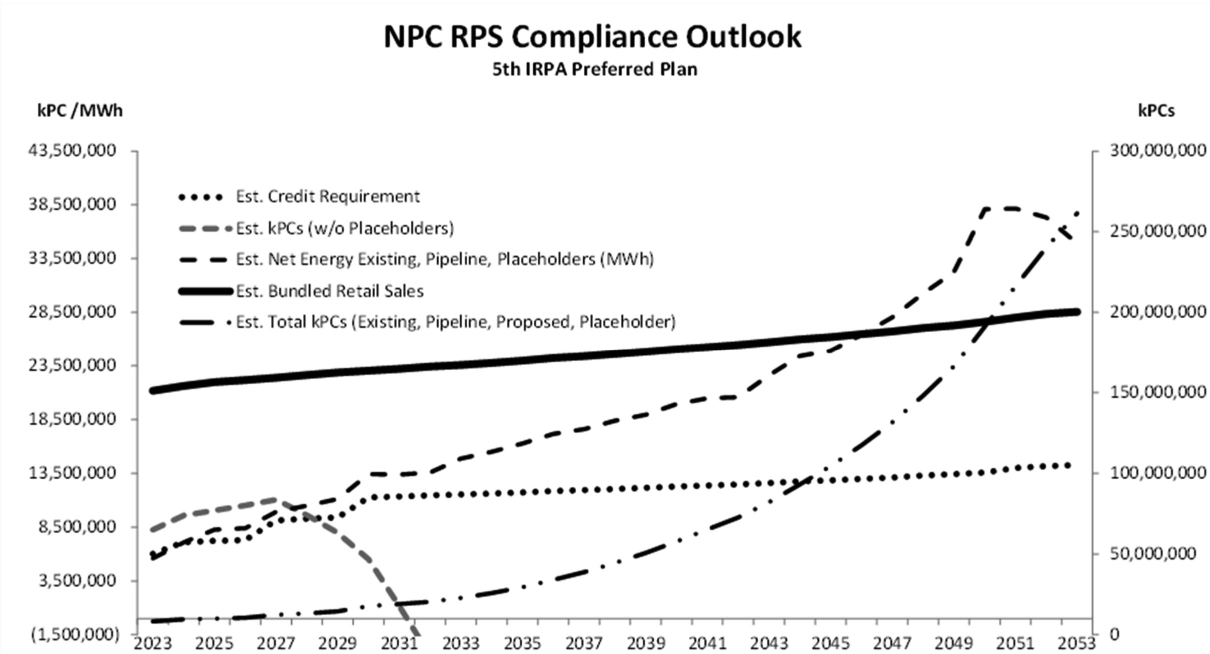
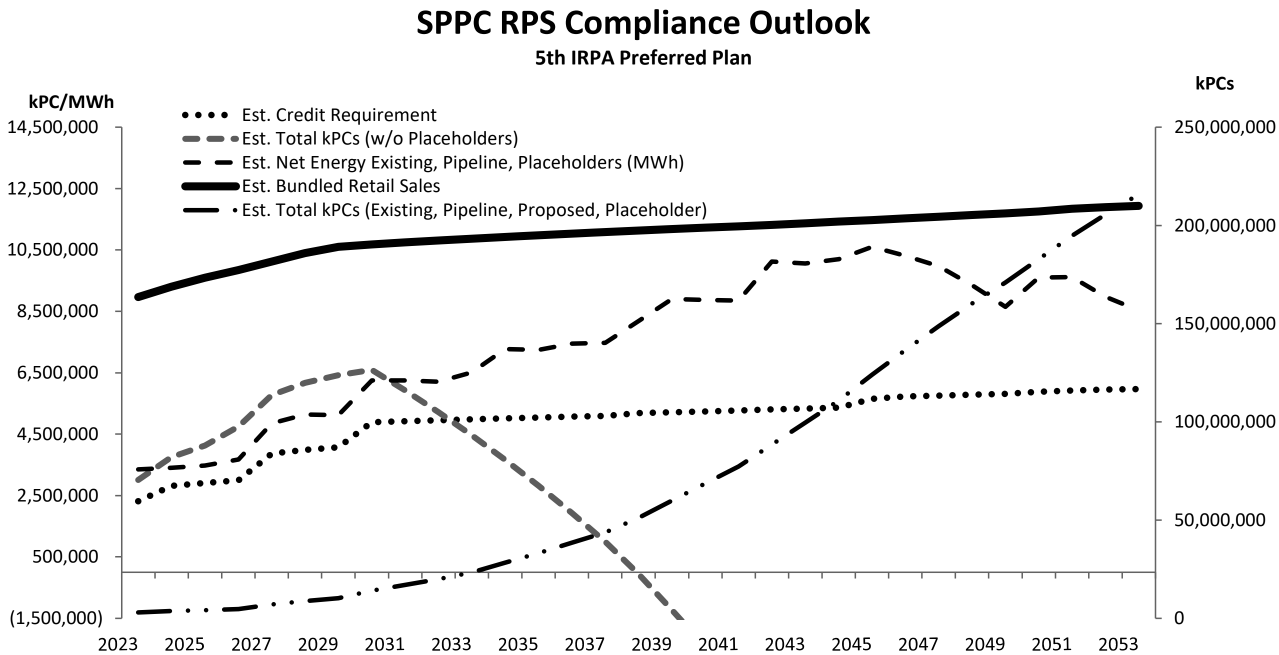


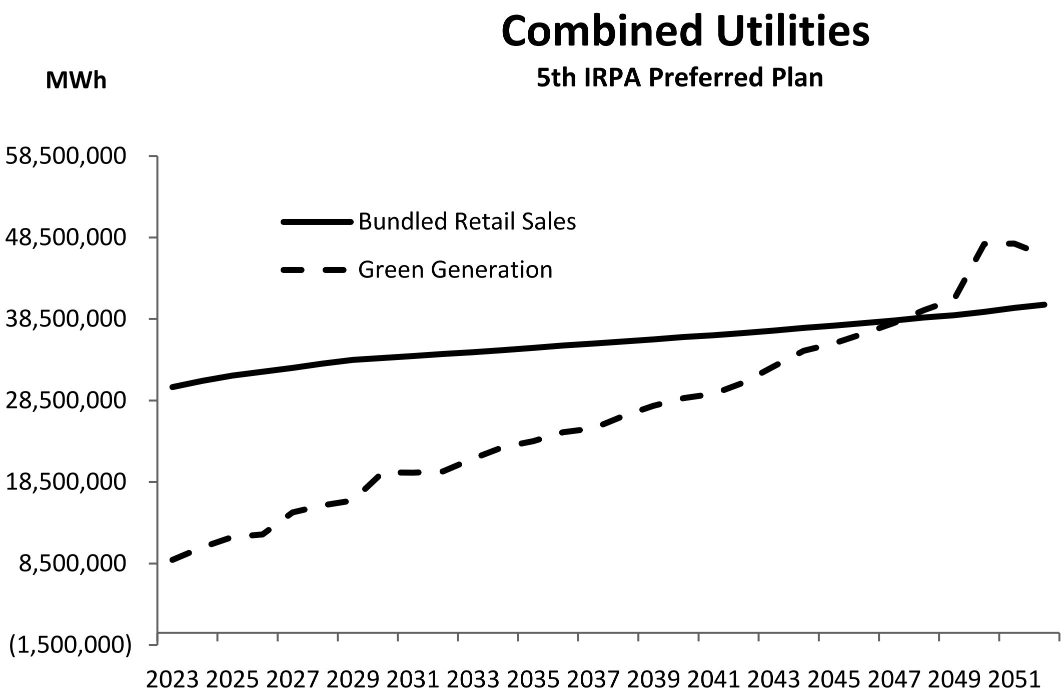
Figure REN-5 below is the same chart and table showing the compliance outlook for Sierra given the above assumptions.

FIGURE REN-5 SIERRA RPS OUTLOOK PREFERRED PLAN



Finally, Figure REN-6 below is a chart showing total green generation versus bundled retail sales. This chart is for illustration purposes. The chart shows that the Companies' preferred plan is consistent with the state-wide 2050 renewable energy production goal.

FIGURE REN-6 NV ENERGY RENEWABLE GENERATION VS RETAIL LOAD WITH THE 2 PROPOSED PROJECTS AND PLACE HOLDERS



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

Technical Appendix REN-1 contains the 12x24 supply table for Sierra Solar. Technical Appendix REN-2 is a list of the placeholders, expected sales, and credits by source for cases in Figures REN-4 and REN-5 above. It also contains forecasted sales and renewable generation data for the combined utilities chart in Figure REN-6.

D. Origination/Renewable Energy

The Companies are presenting two projects: Sierra Solar and Crescent Valley Solar. Amargosa Valley Solar Energy Zone details are included for informational purposes and the Amargosa Solar project will be brought forward for the Commission's approval in a subsequent IRP or amendment. The Companies seek Commission approval to build, own and operate the Sierra Solar project. For Crescent Valley, the Companies seek only the approval to purchase the project development assets and a complete project approval will be brought forward for the Commission's approval in a subsequent filing.[44] For Amargosa Valley Solar Energy Zone, the informational details are included for the Bureau of Land Management ("BLM") Solar Energy Zone land auction. As described further below, the Companies would continue the development efforts on Crescent Valley and Amargosa Valley Solar Energy Zone and, when full cost, performance, and schedule information is prepared, bring the full renewable projects to the Commission for approval.

Sierra Solar and Crescent Valley Solar projects are proposed to meet several business and policy objectives including meeting customers' demand for green energy,[45] serving the ESA with MSG Las Vegas, LLC, compliance with the Nevada RPS, meeting resource adequacy needs for native load and progressing towards the Nevada policy goal of matching 2050 electricity sales with carbon-free generation.

The proposed projects are summarized below in Table REN-4.

TABLE REN-4 NEW RENEWABLE PROJECT SUMMARY

Project	Counterparty	Technology	Capacity	Expected Commercial Operation
Sierra Solar	NV Energy	Solar PV and BESS	400 MW PV 400 MW BESS	BESS: On or before 7/1/2026 Solar: On or before 4/1/2027
Crescent Valley Solar	Invenergy NV Energy	Solar PV and BESS	149 MW PV 149 MW BESS	TBD*

* As Crescent Valley Solar project is an asset purchase at this time, a targeted commercial operation date is not yet established.

The Companies propose that Sierra Solar will be allocated 60 percent to Nevada Power and 40 percent to Sierra. The Sierra and Crescent Valley Solar projects are expected to produce a combined estimated total of 1,503,167 MWh of renewable energy and 1,429,515 associated PCs annually.

The solar PV and BESS projects will utilize PV and lithium-ion technology, respectively, which is a proven and well demonstrated technology to ensure the highest availability. Both Sierra Solar and Crescent Valley facilities have a Large Generator Interconnection Agreement ("LGIA") fully

[44] The acquisition consists of the development work assets of the project developer which include, but are not limited to, site control agreements, interconnection agreements, permits, and engineering work.
[45] Results of 2020 ballot question number 6, available at https://silverstateelection.nv.gov/ballot-questions/.

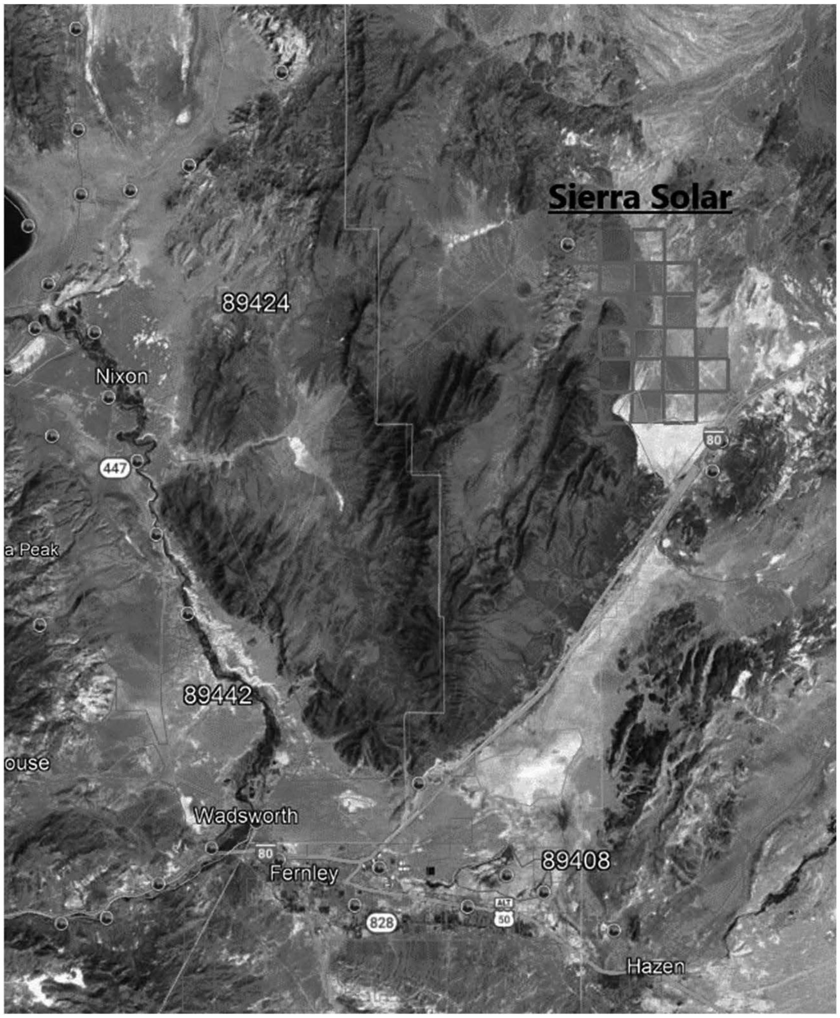
executed. Interconnection, site control, material permits, and other related facility details are included in Technical Appendix REN-3, Sierra Solar and BESS Due Diligence Summary (Confidential). Amargosa Valley Solar Energy Zone is in the initial development stage with site control secured and project design and permitting underway.

1. Sierra Solar

The proposed Sierra Solar Phase I project consists of a 400 MW solar PV with a 400 MW lithium-iron-phosphate ("LFP") BESS facility. 1:1 solar photovoltaic to BESS ratio is preferred at this time because this option offers higher capacity while also helping with lower solar curtailment. The project will be rate-based, developed by NV Energy, and will be allocated 60 percent to Nevada Power and 40 percent to Sierra. As a self-developed site, the Companies avoid the high developer cost premiums, as well as risk of developer termination agreements, while allowing the Companies to control the use and reuse of the facility more fully for future development phases. Additionally, the Companies' ownership of Sierra Solar will also help optimize utilization of the residual asset life after a typical 25-year contract term for similar assets. Sierra Solar is in the advanced development stage with site control, executed interconnection agreement, secured solar panel supply and project design and permitting underway. Execution of Phase I at this time will also support efficient execution of future project phases at the same site. Sierra Solar also supports reduction in market dependence for energy and capacity while supporting the State of Nevada's energy policy goals in Senate Bill 358 (2019) and recently passed Assembly Bill 524 (2023). Additionally, a portion of this project is expected to serve MSG Las Vegas, LLC, through an ESA that has been filed with the Commission in a separate docket and is currently pending approval. MSG Las Vegas, LLC estimates its peak load at 28 MW.

As shown in Figure REN-7, Sierra Solar is located in Churchill County approximately 15 miles northeast of Fernley, Nevada, sited on private land owned by Sierra.

FIGURE REN-7: Sierra Solar Map



The project site consists of 6,787 acres purchased in 2022 from a private seller. It is near the load pocket for northern Nevada in a region of anticipated increased development. Renewables development at this site will support a master plan development for transmission in the Fernley area. Section 7.B. of the Transmission Plan provides additional details. The site will likely support expansion to 1,000 MW of solar with equivalent BESS capacity in subsequent phases of development. There is also potential for geothermal development due to availability of sub-surface rights at the site and neighboring parcels and gravity storage due to some parcels with adequate slope and elevation change. Interconnection requests have been filed for 700 MW with 4-hour battery and 300 MW with 4-hour battery; however, at this time, the Companies seek Commission approval of the network upgrades for the 700 MW LGIA which is adequate to support the proposed project of an initial 400 MW development. The commercial operation date for the 400 MW with 4-hour BESS is targeted to be on or before July 1, 2026, followed by commercial operation of the 400 MW solar PV on or before April 1, 2027. The Companies may place in service partial PV or BESS capacities prior to the above dates if feasible for testing and commissioning.

The total capital project cost of the 400 MW solar and 400 MW BESS is estimated to be $1.5 billion, with transmission costs. Specifically, the Companies are estimating approximately $734 million project cost without transmission for the solar PV portion and $731 million for the BESS portion. The Sierra Solar project is expected to provide energy for a 30-year period at a hybrid levelized cost of energy of $86.77 per MWh and will be $38.25 per MWh and $13,622.56 per MW-month when estimated as energy and capacity price separately for comparison purposes. A comparison of Sierra Solar relative to solar plus storage project proposals received in the Companies' 2023 RFP is presented in Table REN-5. Sierra Solar is expected to generate approximately 1,142,508 MWh and 1,086,528 PCs annually.

Project costs incurred thus far include land purchase sale agreement, transmission interconnection expenses, due diligence, and project management fees. Technical Appendix REN-4 contains detailed information about the project costs. In performing the Economic Analysis and creating the Financial Plan, the Companies overstated the Sierra Solar project costs based on information which has since been updated. Specifically, the Economic Analysis and Financial Plan were based on Sierra Solar PV cost of $759 million and Sierra Solar BESS cost of $756 million. Thus, the Sierra Solar costs for the PV and BESS components were each overstated by about $25 million.

NV Energy estimates that the Sierra Solar project will provide approximately 500 construction jobs over the development periods through 2027. Based on data extrapolated from the Dry Lake solar plus storage project,[46] the facility is expected to provide approximately eight permanent jobs with an average wage of $38 per hour, for an estimated total payroll of more than $16.4 million over 25 years. The Companies are committed to using the International Brotherhood of Electric Workers ("IBEW") Local Union 401 members for the covered electrical work.

Critical Facility Designation for Sierra Solar

With this filing, the Companies are requesting that Sierra Solar receive the critical facility designation pursuant to NAC § 704.9484. The regulation authorizes the critical facility designation for any, or a combination, of the criteria below:

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

The project will provide NV Energy's customers the benefits from all associated environmental and renewable energy attributes as the company-owned solar plus storage resource will help reduce

[46] *See* Docket No. 20-07023, 4th Amendment to the 2018 IRP, Application Exhibit A – Narrative.

dependency on fossil-fueled generation and the volatile wholesale market, promote diversity of supply side resources and retail price stability, and protect reliability. In addition, Sierra Solar contributes to the Companies' RPS compliance and achieving the state-wide goal of zero net carbon by 2050.

Turning to the developing renewable energy resources criteria first, as a 400 MW solar resource paired with a large dispatchable 400 MW BESS, Sierra Solar is a new type of a project for the Companies and represents a new chapter of renewable energy development. Sierra Solar PV and BESS will support future renewable energy development. There is a potential 600 MW additional solar and BESS capacity on the adjacent land parcels that are also within the Companies' control as part of the Sierra Solar land purchase. The Companies will build upon the permitting, engineering, procurement, and operational experience gained from Sierra Solar to develop future renewable energy resources.

The Companies continue to face supply issues with existing resources. The Companies also have renewable energy supply obligations per the existing green tariff programs like NV GreenEnergy Rider and Energy Supply Agreements executed and approved per the Large Customer Market Price Energy and Market Price Energy tariffs. Any resource pipeline cancellation, existing resource underperformance for another power purchase agreement or Company-owned resources and ability to procure future resources may present additional challenges to RPS compliance. These statutory and contractual obligations continue to be met by the same pool of the Companies' renewable energy resources and are affected by renewable resources cancellations or delays. Sierra Solar's commercial operation in the 2026 and 2027 timeframes is critical for fulfilling future RPS compliance obligations in the face of uncertainty about the developers' ability to deliver contracted and approved renewable projects. Therefore, the Sierra Solar project is a critical facility required for continued fulfillment of a statutory mandate.

Sierra Solar adds diversity of supply as a renewable resource capable of providing energy during daytime, evening, and nighttime hours. It reduces the open capacity position via a large dispatchable BESS, larger than any BESS currently in NV Energy's portfolio, available in the net-peak evening hours after solar production has dropped off. The Sierra Solar project would help reduce dependency on fossil-fueled generation and wholesale energy market, providing price stability as it is unaffected by variable fuel costs.

Finally, the location of this project is ideal to protect and enhance system reliability. This generation will be connected to the existing Valmy – East Tracy 345 kV line #3422 at the proposed Lantern 345 kV substation. The generation will be in close proximity to the Tahoe Reno Industrial Center ("TRIC"), Fernley and Fallon areas which have experienced large amounts of load growth and are forecast to continue to see extensive load growth. Having generation located close to the load reduces system losses and improves system reliability. Phase two of this project will include an additional 600 MW of generation and the addition of a new 345kV transmission line from

Lantern Substation to Veterans Substation to Comstock Meadows Substation. This will further improve system reliability by providing additional generation close to the anticipated load growth and adding additional transmission capacity to deliver the generation to the load.

Pursuant to NAC § 704.9484, the critical facility designation may be received by meeting just one of the five listed criteria. The aforementioned benefits of Sierra Solar demonstrate that the project meets all five of the listed criteria.

The regulation contemplates the following incentives for a facility designated as critical, without limitation:

(a) Earning an enhanced return on equity on the designated critical facility over the life of the facility;

(b) The inclusion in the rates of construction work in progress ("CWIP") associated with the designated facility; and

(c) Designating costs incurred to construct the designated critical facility as a regulatory asset eligible for recovery under NAC § 704.9523.

If the Commission designates Sierra Solar as a critical facility, the Companies request to be allowed to:

(a) include the CWIP balances from the Sierra Solar PV and BESS project in rate base for general rate cases (or any other recovery mechanism or filing that would allow the Companies to update the CWIP balance in rate base, which may or may not be in place today, such as a capital recovery mechanism that the Companies may file in the future) prior to the unit being placed into service; and

(b) include the Sierra Solar PV and BESS project expenses, depreciation and operating and maintenance expenses, after the in-service date and until included in rates, in a regulatory asset with carrying charges.

The Companies are requesting this cost accounting treatment because constructing Sierra Solar will involve significant construction expenditures and, without CWIP, no cost recovery until the project is in rate base and has gone through a rate case. These large expenditures without contemporaneous cost recovery are detrimental to the Companies' financial condition, particularly Sierra's. CWIP in rate base treatment has traditionally been a solution for this circumstance.

> In the past, the Commission has allowed a utility to place CWIP into rate base because significant construction costs may be detrimental to the utility's financial situation. CWIP in rate base aids in offsetting the negative effects of regulatory lag by increasing the utility's cash flow and mitigating the impact of the financial requirements of the 514 MW [Tracy unit] addition. CWIP in rate base will also mitigate the impact of the 514 MW on the company's

credit rating.[47]

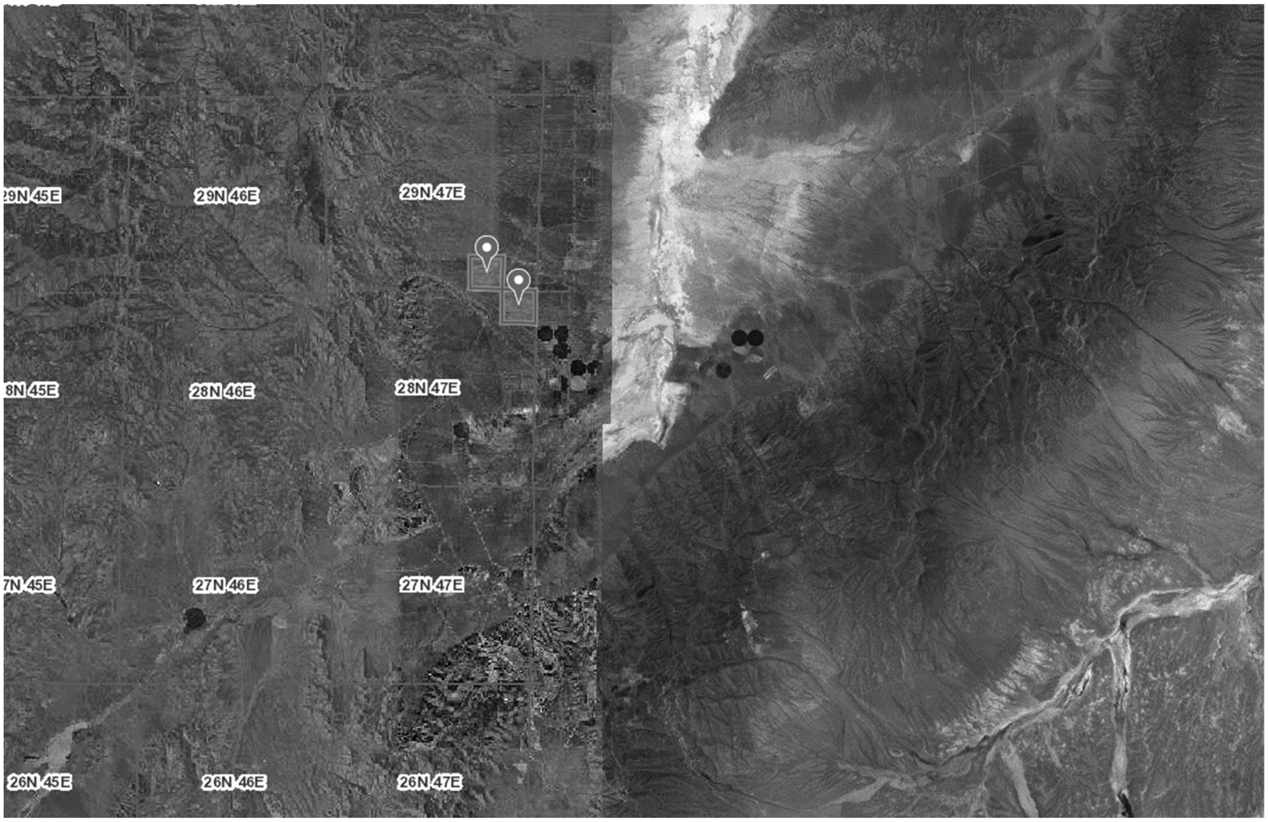
The requested accounting treatment is comparable to the accounting treatment previously granted for ‘the Lenzie Facility (Moapa Energy Facility) and 514 MW Tracy unit. In Docket No. 04-6030, the Commission approved NV Energy’s proposal to record Lenzie Facility construction costs in the CWIP account and subsequently clear and place these costs in each of Nevada Power’s next successive general rate cases.[48] The Commission accorded similar treatment to Sierra with respect to its Tracy 514 MW unit request.[49] Lenzie was also allowed regulatory asset treatment for depreciation and carrying charges associated with the Lenzie investment.[50] Both Lenzie and Tracy construction costs were allowed an ROE adder.[51] The Companies are not requesting an ROE adder for Sierra Solar.

2. Crescent Valley Solar

Crescent Valley Solar (“CVS”) is planned for future development of a 149 MW solar PV with 149 MW BESS facility. CVS is located in Sierra’s service territory. The project site and the development asset purchase agreement consist of 1,280 acres on private land leased from two landowners, and is located in Lander County, Nevada, as shown in Figure REN-8 below. The project is located approximately 46 miles SE from Valmy station.

[47] *See, e.g.,* Docket No. 05-8004, December 14, 2005, Order at 53.
[48] September 21, 2004, Order at 22-23.
[49] Docket No. 05-8004, December 14, 2005, Order at 53-54.
[50] Docket No. 04-6030, September 21, 2004, Order at 22-23.
[51] *Id.*; Docket No. 05-8004, December 14, 2005, Order at 53-54.

FIGURE REN-8: Crescent Valley Solar Map



An LGIA has been executed for 149 MW which will allow for solar and BESS.

The project has an expected net capacity rating of 149 MW. Once developed, the site is expected to generate approximately 360,569 MWh and 342,987 associated PCs annually. The Companies have been in negotiations with the developer to acquire the project assets and have reached an agreement on a purchase price of [redacted] The asset purchase agreement was executed on May 26, 2023, and the Companies are continuing their due diligence for the project development. A copy of the asset purchase agreement is provided in Technical Appendix REN-6 and its due diligence summary is provided in Technical Appendix REN-7. Due to the Companies' large open capacity position and anticipated customer load growth in its service territory, the Companies are requesting [redacted] to purchase the project assets at this time in order to secure the project when it became available.

The following updates are only included for informational purposes:

Amargosa Valley Solar Energy Zone

The Amargosa Valley Solar Energy Zone project is planned for future development of a solar PV with BESS facility. The Companies intend to self-develop the project to control cost and schedule while maximizing value for customers. The project is located in Nye County, Nevada, approximately 10 miles SE from the town of Beatty, Nevada, as shown in Figure REN-9 below.

FIGURE REN-9: Amargosa Solar Map

Amargosa Valley Solar Energy Zone has further been designated as a Solar Energy Zone ("SEZ") by the Department of the Interior's BLM. SEZ are pre-screened by the agency as areas with high solar potential and minimal cultural and natural resource conflicts, thus enabling expedited development of renewable energy resources. The project site contains two parcels dubbed A and B, consisting of 3,775 and 3,451 acres, respectively. BLM held an auction for utility-scale solar development in June 2023, in which the Companies placed the winning bids of $35.25 million and $46.6 million for the aforementioned parcels, respectively, to secure the project when it became available. Technical Appendix REN-8 contains further detail related to the land lease auction documentation. The Companies will continue due diligence for the project development and bring the project forward for the Commission's approval in a subsequent IRP or amendment.

Valmy BESS

The Companies evaluated the Valmy BESS project but are not requesting approval for it at this time as part of the Preferred Plan. Valmy BESS is a 200 MW BESS with four hours of storage on the site of Sierra's coal-fired Valmy Generating Station. The BESS can provide (1) dynamic voltage support in the Carlin Trend load pocket and (2) needed capacity to the Companies' system. It is expected be an LIP battery connected to the existing Valmy 345 kV Substation and is expected to reach commercial operation in December of 2025.

If approved, the Valmy BESS will be developed and allocated 50 percent each to Nevada Power and Sierra. Sierra will retain an EPC contractor to install company-provided batteries. Sierra will evaluate whether to contract for operations and maintenance services, self-perform the work, or a combination of contracted and self-performed.

The Valmy BESS is the result of the Companies' 2022 Spring BESS RFP. The results of the first round were confidentially summarized in Technical Appendix REN-6 provided in Docket No. 22-11032. While that bid event concluded earlier this year, the Companies re-issued another battery RFP on April 24, 2023, in order to obtain more recent pricing. The price of lithium is subject to various market influences, and it has experienced significant volatility, particularly over the past six months. The most recent RFP evaluation continues at the time of this filing. However, the most up-to-date pricing was utilized for production cost modeling and revenue requirement determinations. Based on the most recent bids received when the lithium index was at 350,000 Renminbi ("RMB")/Metric Ton ("MT"), the Valmy BESS is expected to cost approximately $409 million without ITC consideration;[52] however, the final cost may change depending on the lithium market price at time of manufacturing.

As described in the Economic Analysis section 8.D of the Plan, more capacity is needed for northern Nevada than this Amendment provides. Valmy was chosen as the location due to the need for capacity in northern Nevada, the need for voltage support in the Carlin Trend region, and the expectation that future solar development in the region will benefit from the BESS's ability to absorb potential excess solar generation. Furthermore, this location is very close to an existing substation and the land is controlled by Sierra. On a parallel path, the Companies are pursuing discussions with other developers and customers having generating assets that support similar voltage support needs in the Valmy region.

Additionally, the previously approved Hot Pot and Iron Point projects are no longer under development as planned. In January of 2023, the Companies received Notices of Termination of the Build Transfer Agreements for the Iron Point and Hot Pot projects, respectively, from the project developer. In March 2023, the Companies responded acknowledging the developer's

[52] This project was disapproved in Docket No. 22-11032 at an estimated cost of $466 million. Since then, lithium costs have significantly decreased hence the lower, $409 million, estimated cost noted here.

intention to terminate the build transfer agreements and offered a formal termination agreement. Subsequently, in April 2023, the developer responded with assertion that the original notice served as valid termination, and a formal termination agreement was unnecessary. The Companies responded to the developer in June 2023 with notices of termination of the agreements for each of the projects. Therefore, at the time of this filing, each party has provided the other with notification of termination of the build transfer agreements for Iron Point and Hot Pot, and thus the projects as previously approved are no longer moving forward. Potential damages recovery discussions between the parties are ongoing and not final at this time. Moreover, the developer bid the Iron Point and Hot Pot projects into the Companies' 2023 Open Resource Request for Proposals as a combined Build Transfer Agreement project with updated pricing and commercial operation dates. The bid was not the most competitive with other bids in the RFP, nor was it selected as the best Valmy area solution, as described in the Transmission, Economic, and Finance sections of this plan. Table REN-5 shows a comparison of solar plus storage project pricing of the bids received in the RFP, based on a hybrid levelized cost of energy ("LCOE"). As the table demonstrates, the re-bid Hot Pot and Iron Point had a considerably higher LCOE compared to the confidential Project Option B2 bid and Sierra Solar. In fact, Sierra Solar is the lowest LCOE project.

TABLE REN-5: Solar Plus Storage Project Pricing Comparison [REDACTED]

Developer	**A**	**A**	**B**	**NV Energy**
Project Option	**IP/HP 1**	**IP/HP 2**	**2**	**Sierra Solar**
Solar Capacity (MW)	**600**	**600**	**700**	**400**
BESS Capacity (MW)	600	600	700	400
Duration (hours)	4	4	4	4
Interconnect	120 kV; 345 kV	120 kV; 345 kV	345 kV	345 kV
COD	6/1/2026	6/1/2026	6/1/2027	7/1/26 BESS; 4/1/27 PV
Price	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	$86.77

*Sierra Solar was not included in the Companies' 2023 RFP; it is presented here for comparison. Projects with similar attributes (e.g., technology, capacity, COD) are included in this table for comparison with Sierra Solar. Developer A Project Options IP/HP 1 and 2 are the same project with different pricing. Project Option IP/HP 1 conforms with the NV Energy pro forma contract and has a slightly higher price. Project Option IP/HP 2 does not conform to the NV Energy pro forma contract and has a lower price.

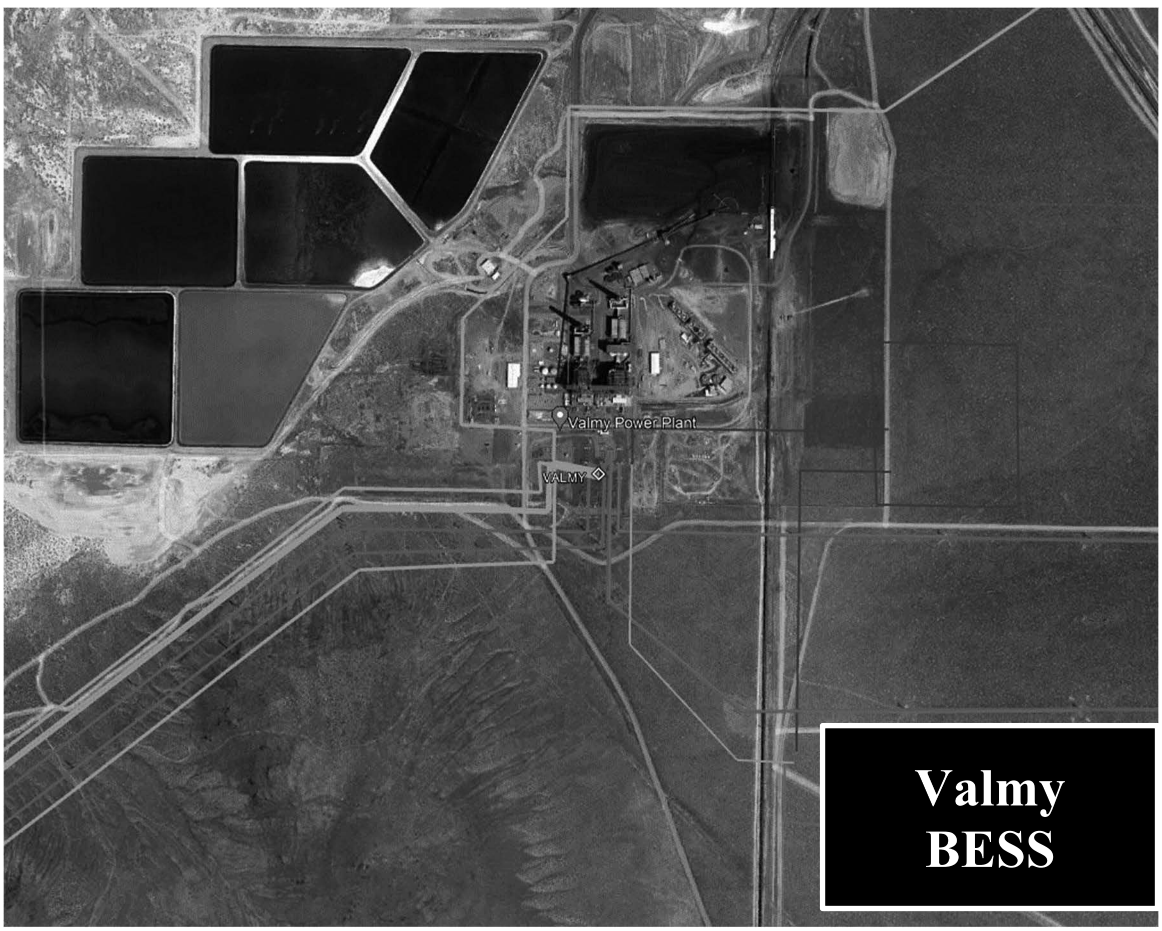
**IP and HP projects are bundled for the above LCOE comparison due to similar project scales and separate project costs were included in the economic analysis.

***Price includes project price plus required transmission network upgrade costs.

Because the Iron Point and Hot Pot projects as previously approved are no longer being developed, it is critical for the Companies to expeditiously secure an alternative long-term plan for the Valmy area. Valmy BESS could provide a compliment to the re-powering of the Valmy coal units, and to provide capacity and voltage support. Additional detail for the complete solution to the Valmy region capacity and voltage support is discussed in the Transmission Plan. The Provisional Large Generator Interconnection Agreement ("PLGIA") study indicates there is transmission capacity.

The Valmy location is a good location for a grid-tied storage project because it represents an intersection of considerations for location: land control, proximity to interconnection, and grid support. The Valmy BESS location is depicted below in Figure REN-10. An LGIA request and a Designated Network Resource ("DNR") application have been submitted.

FIGURE REN-10 Valmy BESS Area Map



In their most recent RFP, the Companies received bids for additional renewable energy projects. The project proposals included current developer-provided pricing for standalone BESS that has been incorporated into the Resource Planning models for the Alternate Plan. Table REN-6 below compares the Valmy BESS against standalone grid-tied BESS project bids in the Companies' 2023 RFP.

TABLE REN-6: COMPARISON OF VALMY BESS TO STANDALONE STORAGE PROJECT BIDS IN 2023 RFP [REDACTED]

Developer	Project Option	BESS Capacity (MW)	Duration (hours)	Total MWh	Utility	COD	Price	LCOE ($/MWh)
A	1	100	4	400	NPC	5/31/2025	[redacted]	[redacted]
A	2	400	4	1600	NPC	5/31/2026	[redacted]	[redacted]
A	3	450	4	1800	NPC	5/31/2026	[redacted]	[redacted]
B	1	125	4	500	SPPC	5/1/2026	[redacted]	[redacted]
B	2	125	4	500	SPPC	5/1/2025	[redacted]	[redacted]
B	3	50	4	200	NPC	5/1/2026	[redacted]	[redacted]
B	4	50	4	200	NPC	5/1/2025	[redacted]	[redacted]
C	1	200	4	800	NPC	7/1/2027	[redacted]	[redacted]
C	2	100	4	400	NPC	7/1/2027	[redacted]	[redacted]
C	3	100	4	400	NPC	7/1/2026	[redacted]	[redacted]
NV Energy	Valmy BESS	200	4	800	SPPC	12/1/2025	$ 409,000,000	$ 153.30

*Price includes project price plus required transmission network upgrade costs.

Table REN-6 above shows the Valmy BESS compares favorably to bids received from third-party developers during the Companies' 2023 Open Resource RFP on a LCOE basis. Similar to the Companies' resource portfolio that currently contains a diverse mix of baseload and peaking generation assets, the growing portfolio of flexible BESS projects can and will perform many functions that will assist in fulfilling diverse system and customer needs.

Based on data extrapolated from the Dry Lake solar plus storage project, the Companies estimate that the project would have provided approximately 250 construction jobs over the development periods through 2025. After the targeted commercial operation date of December 31, 2025, the facility would have provided approximately four permanent jobs with an average hourly wage of $37 for an estimated total payroll of $12.3 million over 25 years. The Companies are committed to using IBEW Local Union 401 members for the covered electrical work.

<u>Normalization of Investment Tax Credits and Request for Deviation from NAC § 704.6546</u>

The Sierra Solar BESS project is eligible for tax credits under the IRA. If the Valmy BESS project were to move forward, it would also be eligible for tax credits under the IRA. The IRA provides a 30 percent ITC for battery storage projects and allows the Companies to pass through to the customer the full benefit of those credits by opting out of normalization. The Companies intend to opt out of the ITC normalization for the Sierra Solar BESS project and, in the event approved, Valmy BESS project. The Companies request a waiver of NAC § 704.6546, use of separate-entity method by utility members of consolidated group, to take full advantage of those tax benefits. The Companies' deviation request is submitted pursuant to NAC § 704.0097.

NAC § 704.6546 provides:

> 1. In computing federal income taxes, utility members of a consolidated group must use a separate-entity method, rather than a consolidated-company approach which includes impacts of nonutility and affiliated operations.
> 2. As used in this section, "consolidated group" means the combination of two or more affiliated corporations or enterprises for the purposes of financial statements, income tax returns, or both, which may include utility and nonutility operations or entities

With normalization, ITC is recaptured onto the books of the company and amortized as a reduction of income tax expense over the book life of the underlying asset. There is no adjustment to rate base. Without normalization, the treatment is the same except there is a rate base adjustment by the net of two accounts: account 255 capitalized ITC credit carryforward and account 190 unutilized ITC credit carryforward. The result is that rate base is adjusted for any number of credits both generated and utilized by the Companies.

However, if the Companies continue to use the separate-entity method, as required by NAC § 704.6546, they will not be able to monetize the tax benefits when they are generated. Instead, they will have tax credit carryforward balances that will take years to fully utilize. The Companies will not be able to monetize the tax benefits immediately because each utility must generate enough taxable income on its own to absorb the tax depreciation and credits generated each year. Since the benefits are substantial, it will take several years to fully utilize all the tax benefits. Furthermore, the unused tax credit carryforward balances will be recorded on the balance sheet as a deferred tax asset and will be included in rate base. This rate base increase will in turn increase revenue requirement. Granting the waiver of NAC § 704.6546 thus results in a lower rate base and lower revenue requirement.

If the waiver request for NAC § 704.6546 is granted, the account 190 unutilized ITC credit carryforward would be zero. Thus, the full benefit of the ITC credits generated would have reduced rate base and benefit the customers. Accordingly, the deviation from NAC § 704.6546 is for good cause and is in the public interest. The deviation is not contrary to statute.

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.[53] This amended Transmission Plan is built upon the load and resource forecast including proposed generation interconnections and retirements, system characteristics, existing and future transmission facilities and obligations as described in the most recent Transmission Plan filed in the 2021 Joint IRP plus all material amendments to that plan to date. Based on these key system characteristics and subsequent changes, the amended Transmission Plan examines the capabilities of the existing system to determine the need and timing of additional transmission facilities. The plan identifies and requests approval of additional projects that must begin construction within the current 2022-2024 three-year Action Plan period to meet new obligations. The projects in subsection B of this amended Transmission Plan are required to be identified in this amended plan.

Retirement of Coal Combustion at Valmy

The Preferred Plan in the Fifth Amendment presents a complete plan for the Valmy Generating Station that provides the required voltage and generation support for the Carlin Trend area. To facilitate this, a new transmission study was completed exploring the planned retirement of Valmy generation units in 2025, which is provided as Technical Appendix TRAN-1. The retirement dates for the two coal units at Valmy have been discussed in previous regulatory filings. Currently, both Valmy units are planned to retire by the end of 2025. In Docket No. 16-07001, the Commission directed NV Energy to prepare and provide an update to the Valmy LSAP prepared in 2018 and provided as Technical Appendix TRAN-2. The updated report is provided as Technical Appendix TRAN-1. To ensure the thoroughness of that study, the 226 MW of coal-fired TS Power Plant ("TSPP") owned by Newmont Mining Corporation ("Newmont") and located in the Carlin Trend Load Pocket was included in the analysis. Transmission Operations require that either TSPP or Valmy are operational in order to maintain system stability. Both historical events and simulations have shown unacceptable voltage levels and the potential for cascading outages under certain 345 kV line contingencies if one of those generation sources is not operating. More information about the Valmy must run requirement is in the Valmy Must Run report, provided as Technical Appendix TRAN-1. Because TSPP is not owned or operated by NV Energy, its output cannot be depended on for maintaining system voltage. Accordingly, Sierra may not be able to call on the TSPP to support the Carlin Trend. Thus, the analysis for reviewing the system with and without Valmy support will also include system reliability with and without the availability of Newmont's TSPP.

[53] *See* NAC § 704.9385(3).

The Valmy Must Run - 2023 study identified that, under certain system contingencies, when both Valmy and TSPP generation are unavailable, voltage in northeastern Nevada cannot be maintained within acceptable voltage ranges. To address those voltage limitations, the study recommended the installation of dynamic reactive support at Valmy Substation, static reactive support at Humboldt and Falcon Substations and upgrades at Fort Churchill substation to reliably support the system. The Valmy Must Run 2023 deviates from the LSAP completed in 2018 prior study as it includes 537 MW of customer forecasted load in the TRI Center area in the base cases before additional transmission can be built, in this case, the addition of the Greenlink West project at the end of 2026. With the additional load in the TRI Center area, the retirement of Valmy, and with existing generation in Sierra's system enabled, the total import into Sierra's system during heavy load periods can be close to the total system import limit. During these conditions, the current system is not strong enough to survive the loss of certain 345 kV lines without shedding load in both the Carlin Trend and the Reno load pockets. To further exacerbate the situation, upon loss of either the #3419 Humboldt – Rogerson line or the #3428 Falcon – Robinson Summit line, the total system import must be reduced to 600 MW to survive the loss of the next line. Without generation at Valmy, this reduction in import limit may not be achievable without shedding additional load which would be a violation of the North American Electric Reliability Corporation ("NERC") transmission system planning reliability criteria. During these heavy import scenarios, even when adding additional voltage support (both static or dynamic) at Valmy and the Carlin Trend area, load shedding for an N-1 contingency will be required unless Valmy generation is turned on or a new generation source is added to replace Valmy.

The new transmission study confirmed the need for the existing Valmy area generation must-run procedure. Transmission Operations has developed this must-run procedure to mitigate unacceptable reliability conditions for single contingency events, including loss of the north transmission system's specific 345 kV lines. A copy of the Valmy Must Run Key Decision Report is provided as Technical Appendix TRAN-5. After the loss of a 345 kV line, the system must be configured to withstand the next worst-case contingency. The worst-case contingency leads to low voltages throughout the Carlin Trend. Therefore, either a generator must be running before the contingency occurs or one must be started quickly after the contingency occurs. The Valmy generation units require 24 hours to place in service, so they cannot be started quickly. A large quick start generator at Valmy would eliminate the need for the Valmy area must-run procedure. Construction of the Sierra Solar's initial phase of 400 MW will help to replace some of the resource deficiency in the north transmission system but does not resolve the Carlin Trend's post contingency voltage issues discussed previously. The Valmy BESS (Battery Energy Storage System), included in some of the alternative plans, does not have sufficient output duration by itself to support the Carlin Trend area until the existing Valmy generation can be started. The Preferred Plan includes repowering the existing Valmy units to natural gas to enable the required must-run procedure to continue to be used as mitigation. When Greenlink West is completed, it will strengthen the northern Nevada transmission system and increase the system import limit. The import limit will increase by 725 MW from 1,275 MW to 2,000 MW. However, 681 MW of the additional import capacity will be allocated to existing open access transmission tariff requests. NV Energy native load will only receive 44 MW of additional import capacity. Depending on how much of the additional import capacity is actually utilized by transmission system network customers, continued must-run at Valmy may not be required. However, there will likely still be periods when generation is required to be online in the Valmy area. As loads continue to increase in northern Nevada and during planned outages, there will likely be periods when generation is required at Valmy.

B. Specific Requests for Commission Approval to Construct Transmission Projects

The Companies are requesting approval for network upgrades required to interconnect and deliver the Preferred Plan's new generation resources, fulfill interconnection and transmission service requests under the NV Energy Open Access Transmission Tariff and meet load service obligations in a timely manner. The request for approval consists of the following transmission projects:

1. Lantern 345 kV Substation Construction
2. Esmeralda and Amargosa 525/230 kV Transformers Additions
3. Apex Central and Apex East 230/12 kV Substation Construction

1. <u>Lantern 345 kV Substation Construction</u>

The Companies have signed a Large Generator Interconnection Agreement ("LGIA") for and identified as a Designated Network Resource ("DNR"), a solar and battery generation project called Sierra Solar project. The LGIA provides for interconnection and associated interconnection facilities and network upgrades while the DNR designation provides for resource delivery in accordance with FERC regulations. The resources are being developed northeast of Fernley. The project will require transmission network upgrades to reliably move the power to the Reno load pocket because of the limited capacity remaining on the #3421 and #3422 345 kV lines. These improvements include a new collector substation called Lantern 345 kV substation that will be connected via a line fold of the existing Valmy – East Tracy 345 kV line #3422. The first phase of the network upgrades identified in the system impact studies is to construct the Lantern substation, allowing 400 MW of generation commercial operation. The Companies request Commission approval to construct the Lantern Substation.

The location of this project is ideal to protect and enhance system reliability. This generation will be connected to the existing Valmy – East Tracy 345 kV line #3422 at the proposed Lantern 345kV substation. The generation will be located in close proximity to the Tahoe Reno Industrial Center ("TRIC"), Fernley and Fallon areas which have experienced large amounts of load growth and are forecast to continue to see extensive load growth. NV Energy currently has executed contracts for over 1,000 MW of new load growth in this area and we are evaluating large amounts of additional load in this area. Having generation located close to the load reduces system losses and improves system reliability. Phase two of this project will include an additional 600 MW of generation and the addition of a new 345kV transmission line from Lantern Substation to Veterans Substation to Comstock Meadows Substation. This will further improve system reliability by providing additional generation close to the anticipated load growth and adding additional transmission capacity to deliver the generation to the load. These reliability enhancement benefits support designating Sierra Solar as a critical facility pursuant to NAC § 704.9484(2)(a) – the protecting reliability criteria.

<u>Budget and Cost Responsibility:</u> The Companies will be responsible for the costs of the Valmy – East Tracy #3422 345 kV line fold and Lantern substation including the permitting costs requested in this amendment.

<u>Construction Scope:</u> The new Lantern substation will include three 345 kV breakers in a ring bus expandable to a breaker and a half configuration in the future when needed. The communications and protection will also be modified and added to accommodate the Lantern substation. The new substation will also require a control building and metering to be constructed.

FIGURE TRAN-1
LANTERN SUBSTATION PROXIMITY MAP

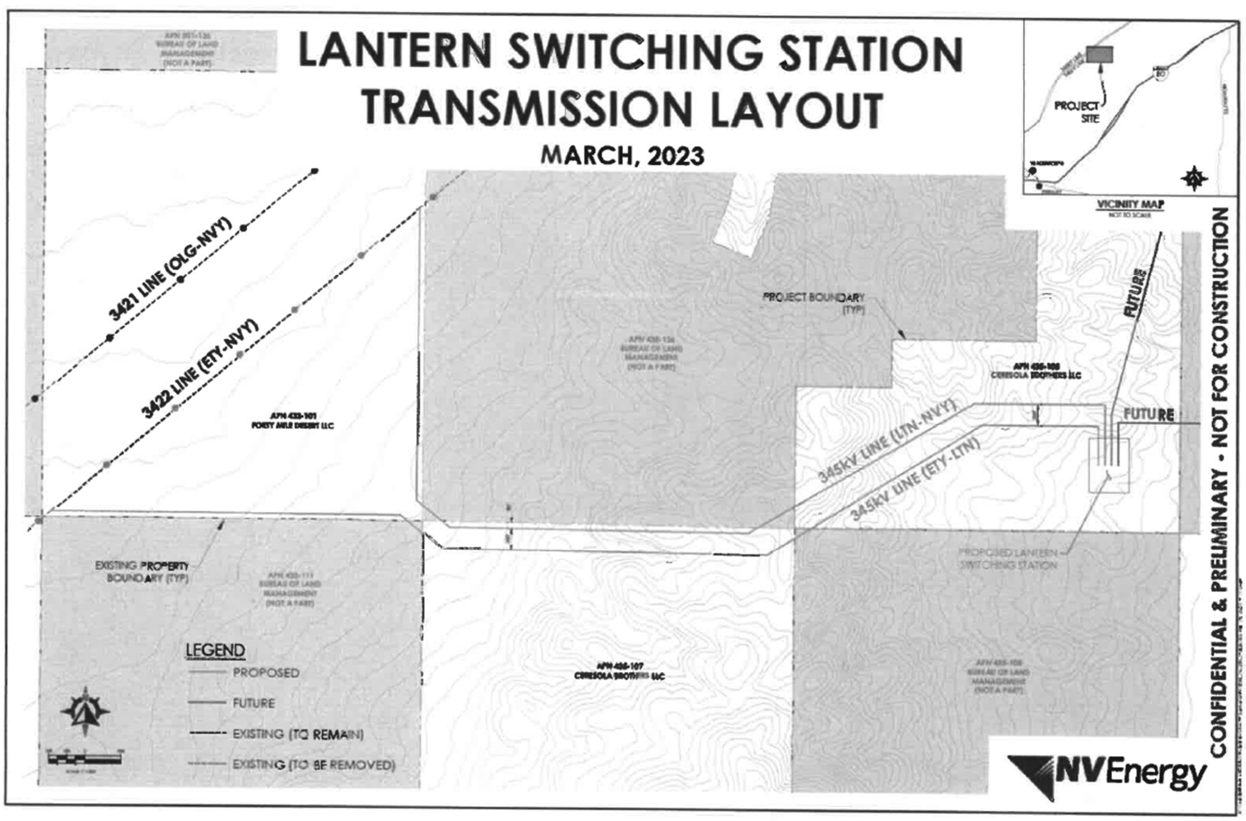


FIGURE TRAN-2
LANTERN SUBSTATION ONE LINE

NV Energy	Lantern Substation Co MH and Co MI	3/10/2023

Legend

- Existing NV Energy Facilities
- Future
- Transmission Provider Interconnection Facilities
- Interconnection Customer Interconnection Facilities
- Company Network Upgrade Facilities
- Prior Queued Projects
- ● Point of Interconnection
- ★ Point of Change of Ownership

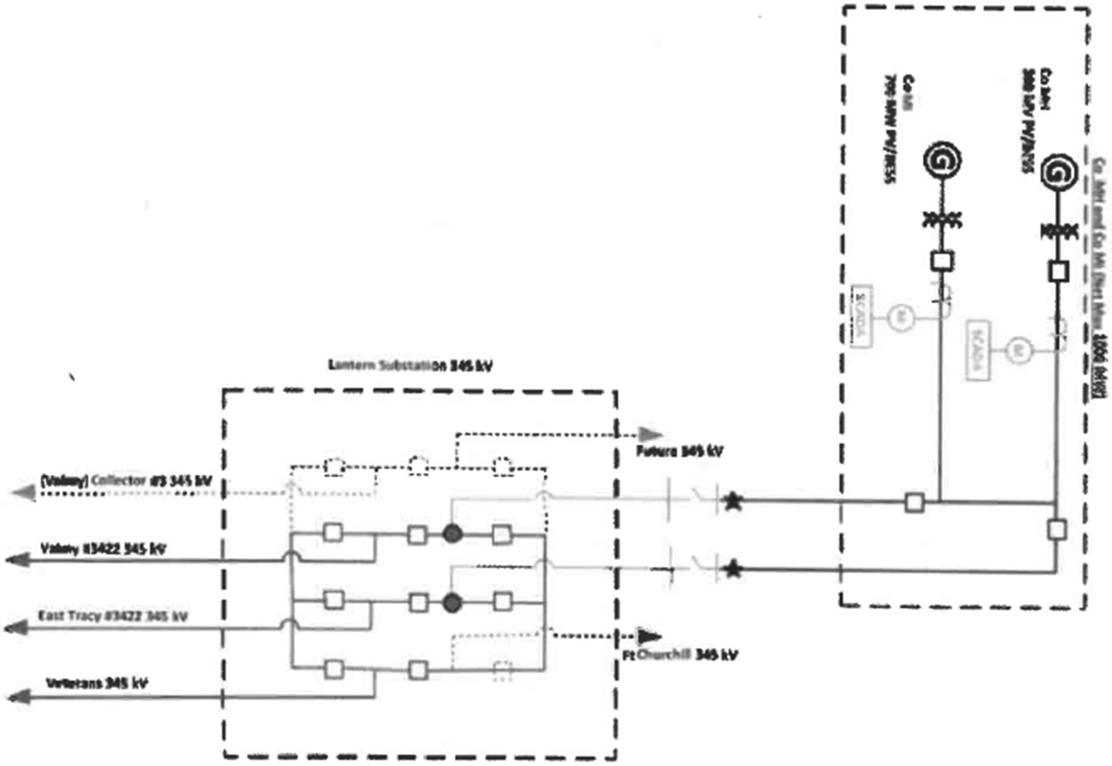


FIGURE TRAN-3
LANTERN SUBSTATION ONE LINE

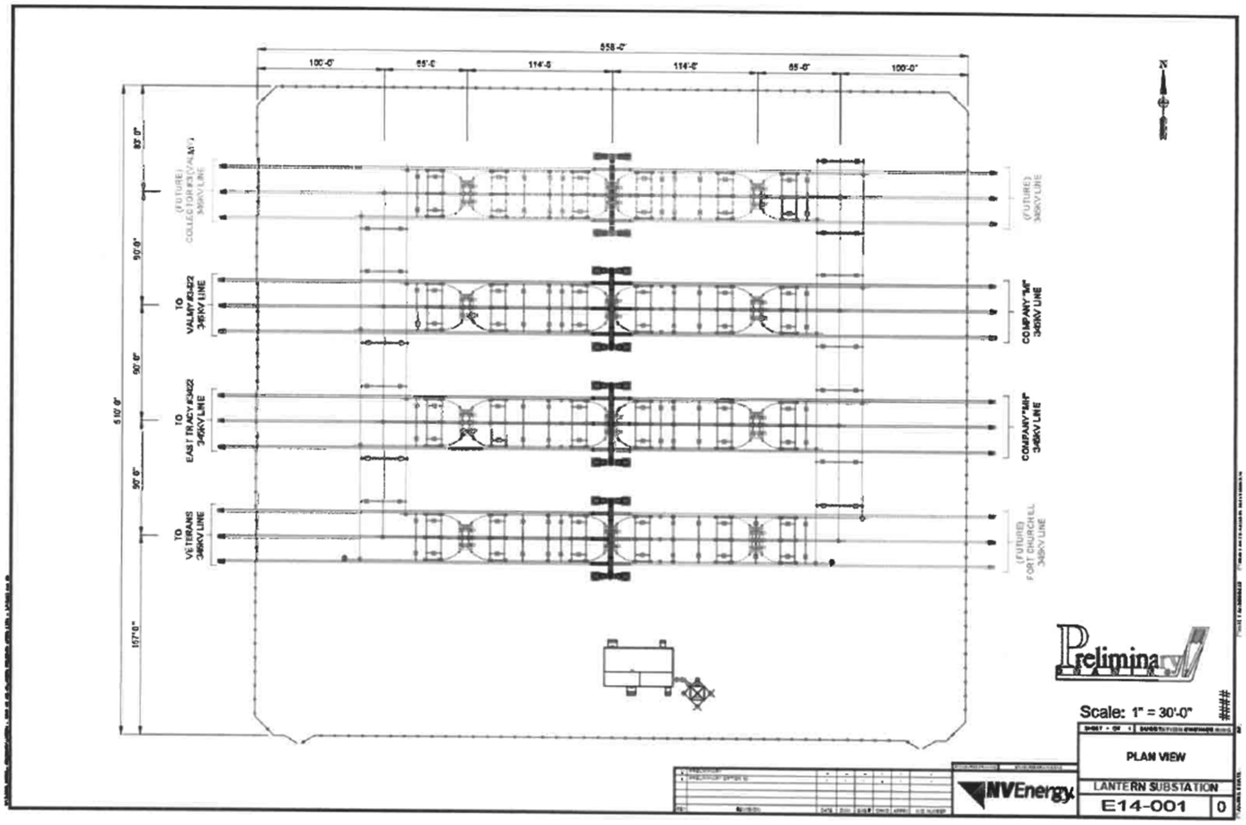


TABLE TRAN-1
LANTERN 345 KV SUBSTATION CONSTRUCTION CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
70.470	0	7.047	21.141	42.282	70.470	0.0

2. <u>Esmeralda and Amargosa 525/230 kV Transformers Additions</u>

The Commission approved the construction of the Esmeralda and Amargosa 525 kV substations in Docket No. 20-07023. Renewable resources interconnecting at the Greenlink West collector substations require construction of 525/230 kV transformers. The Companies have received numerous applications for interconnection on the Greenlink West, at Esmeralda substation totaling more than 9,900 MW (with 5,500 MW at 230 kV and 4,400 MW at 525 kV) and at Amargosa substation totaling 4,958 MW (with 1,408 MW at 230 kV and 3,550 MW at 525 kV). Commercial Operation Dates ("COD") for the interconnecting resources begin as early as 2026. NV Energy is responsible for the cost of the 230 kV facilities required to interconnect the new generation with the various developers. Currently, the Companies are in the process of acquiring construction services and long-lead equipment (e.g., transformers, circuit breakers, steel structures) for Greenlink West substation facilities. To minimize costs through economies of scale and accommodate timely interconnection of renewable resources, the Companies propose to aggregate the acquisition of construction services and long-lead equipment for the Greenlink West substation facilities' 525/230 kV transformers with the ongoing procurements. This proposal is similar to the Commission-approved buildout of Lander 525/230 kV substation in Docket No. 21-06001. The lead times for transformers, breakers, insulators, and switches have nearly doubled over the past two years. Postponing acquisition of long-lead equipment and construction of the 230 kV buildout would increase costs and delay interconnection of renewable resources two years or more. Postponing construction will require the contractors to work in energized 525 kV substations, which may increase costs of supervision and North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") standards compliance. It is estimated that another procurement process for facilities and construction labor and remobilization could be as high as $10 million or more in the future based on the itemized mobilization costs included with Greenlink Nevada substation facilities construction bids received in May 2023.

Accordingly, the Companies request Commission approval to construct the Greenlink West substation facilities' two 525/230 kV transformers simultaneously with the 525 kV switching yards at each location.

<u>Budget and Cost Responsibility:</u> The Companies will be responsible for the costs to construct Esmeralda and Amargosa addition of two 525/230 kV transformers at both substations.

<u>Construction Scope</u>: The Companies will construct all facilities to install two 600 MVA 525/230 kV transformers at Esmeralda substation and to install two 600 MVA 525/230 kV transformers at Amargosa substation. At both sites, this will include construction of all equipment and facilities required to accommodate the transformer, such as transformer oil containment basin, steel structures, 230 kV and 525 kV breakers, switches, bus work, metering, relay protection and Supervisory Control and Data Acquisition ("SCADA"). The planned in-service date ("ISD") is December 2026.

FIGURE TRAN-4
ESMERALDA ONE LINE

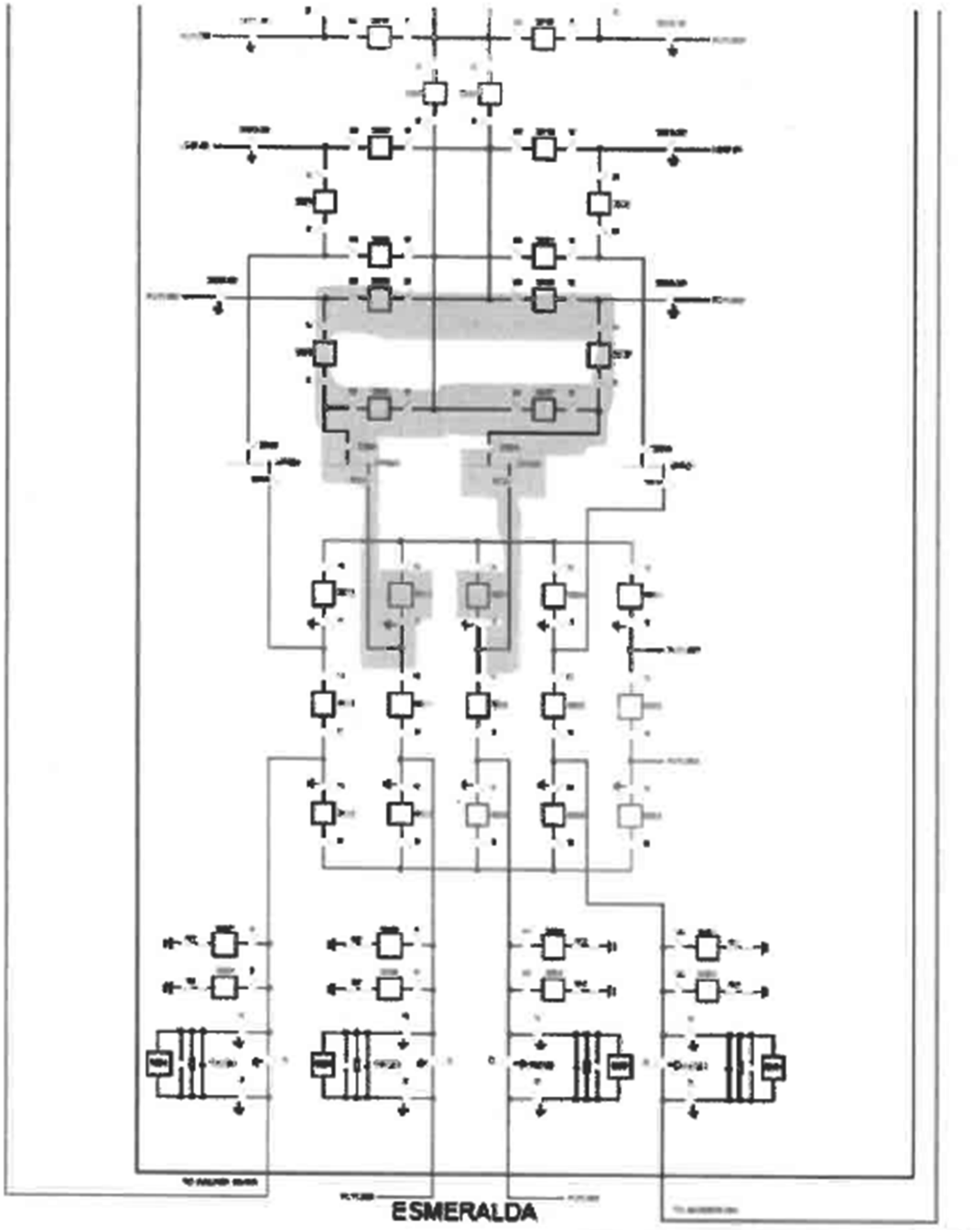


FIGURE TRAN-5
AMARGOSA ONE LINE

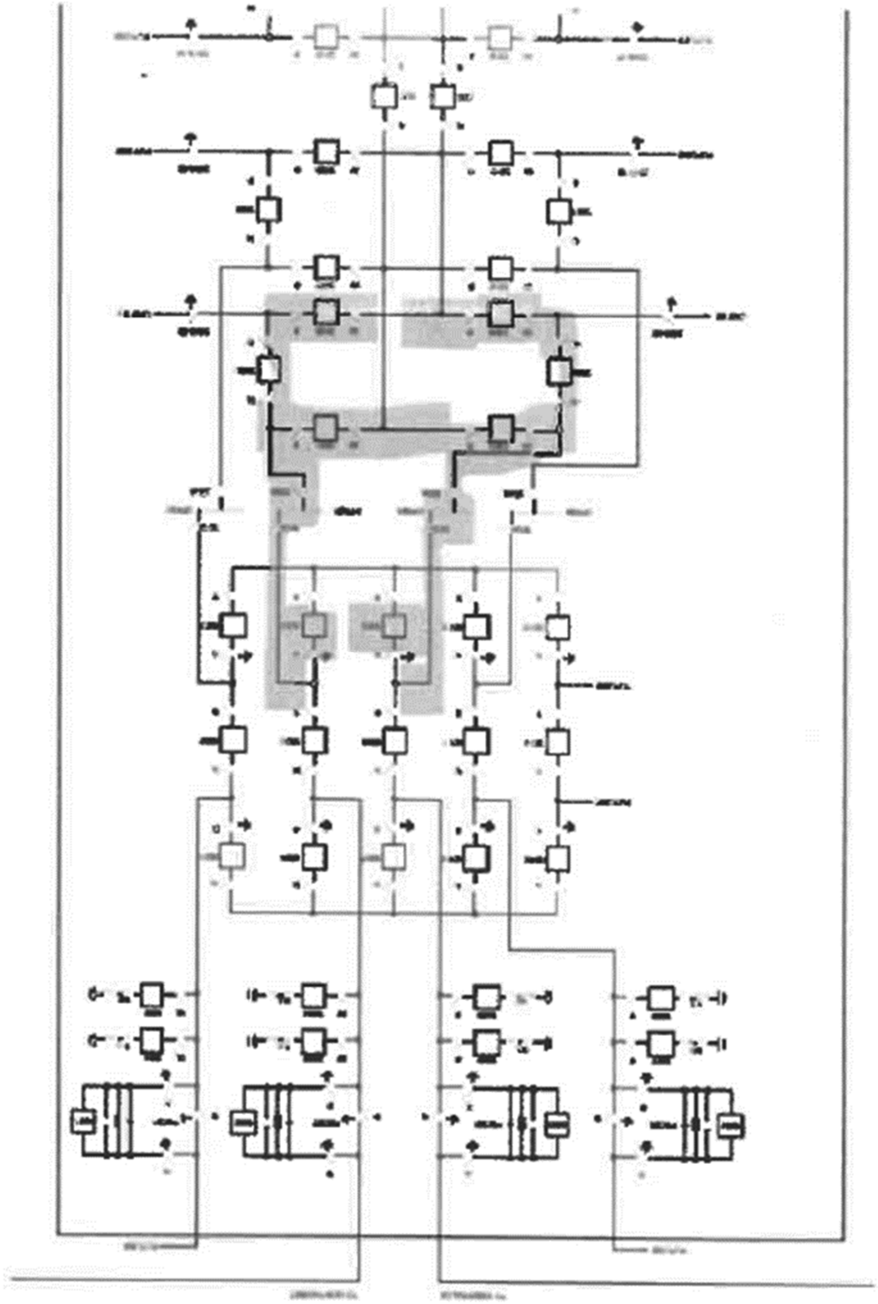


TABLE TRAN-2.1
ESMERALDA 525/230 KV TRANSFORMERS CONSTRUCTION CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
55.6	0	0.7	1.3	20.7	22.7	32.9

TABLE TRAN-2.2
AMARGOSA 525/230 KV TRANSFORMERS CONSTRUCTION CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
40.2	0.0	0.5	0.9	15.0	16.4	23.8

3. Apex Central and Apex East 230/12 kV Substation Construction

Nevada Power has received numerous applications for load service in the Apex area for warehousing, manufacturing, data centers and mixed use. The City of North Las Vegas is collaborating with developers in the Apex area and the city is developing water and sewer projects as well as new roadways to aid in the economic growth of the area. Apex is an ideal area for industrial and commercial development as the rest of the Las Vegas Valley is largely built out or limited by lack of developable land. In June 2023, Senator Catherine Cortez Masto introduced legislation to help with Apex area development by improving permitting. The bill is designed to promote growth and improve the permitting process by allowing the City of North Las Vegas and the Apex Industrial Park Owners Associations to issue permits for new and existing businesses to get the utilities they need to operate. The proposed legislation is known as the Apex Area Technical Corrections Act. Due to current development activity, continued long-term forecasted growth including the availability of land for development, the sophistication of the City of North Las Vegas with planning the Apex area, and the need to provide infrastructure in areas that are in the early stages of roadway development, it is recommended to accelerate the electric facilities needed in the Apex area. The Apex Area Master Plan was presented in Docket No. 22-11032 for "approval of constraint study, environmental studies permitting and land acquisitions of public and private land rights" to start these preliminary efforts to support the growth in the Apex area.

The Apex area has the potential for substantial load and generation growth. Several potential load additions ranging from 15 MW to 460 MW have inquired about electric service in this location. Currently, there is no distribution capacity to accommodate these new loads. The Apex Area Master Plan was strategically planned to allow multiple substations to be placed along a proposed 230 kV loop and phased in as load materializes.

In the first phase, the 230/12 kV Prospector substation was installed and energized to serve loads in the southwest area of Apex. The plan will first maximize the distribution loads at the existing substations in the area (Gypsum and Prospector) then the new 230/12 kV Apex substations will be added individually based on their priority level and customer load locations. The next phases of the plan include both Apex Central and Apex East substations.

Apex Central is proposed as a 500/230/12 kV substation, sourced initially by 230 kV and then by the 500 kV system as loads materialize in the region. Apex Central is an area upgrade project to source several master planned communities. Since Docket No. 22-11032, customer agreements have been signed requesting in-service dates as early as December 2025, which will require the construction of Apex Central (names subject to change) and the Apex Central – Prospector 230 kV line. Apex Central is planned to eventually connect to future 230 kV Apex substations.

Apex East 230/12 kV substation is proposed for a single master planned customer developing northwest of the Companies' Lenzie power plant. A Substation High Voltage Distribution Agreement ("S/HVD") has been executed with the customer with a target in-service date of May 2026.[54]

To reduce the project costs, the existing 230 kV and 525 kV lines are incorporated in the Apex Area Master Plan. Also, to limit the impact and cost of new substations, the planned substations are expandable to accommodate load growth by adding 500/230 or 230/12 kV transformers or high-voltage distribution terminals, as necessary. The Apex Area Master Plan is phased, but the order of the construction phases will be adjusted to accommodate loads as they materialize.

Based on the requests for service received and the current Rule 9 agreements that have been signed, it is necessary to start Apex Central substation project as soon as possible to meet the customers' 2025 in-service dates. Given there is no distribution capacity remaining from the existing substations that could be allocated to these new distribution loads, new capacity is needed. The Companies request Commission approval to construct the Apex Central 230/12 kV substation and the associated Apex Central – Prospector 230 kV line.

Additionally, the Companies request Commission approval to begin Apex East 230/12 kV substation to serve a new master planned customer that has an estimated full build out of 84 MVA. Per the S/HVD, the customer will be responsible for providing the substation site, including rough grading, onsite and offsite improvements, and rights of way at no cost to the Companies. Additionally, the customer is responsible for the prorated costs associated with the first transformer bank and all substation facilities to place the first bank in full operation.

Due to the timing of the in-service dates requested by the customers for these projects and the fact

[54] S/HVD Agreement No. 22-00011 was executed on July 26, 2023.

the projects will require a UEPA permit to construct, the Companies are including the approval request in this amendment filing. The next planned filing is the Companies' 2024 Joint IRP filing scheduled for summer of 2024, which risks not leaving adequate time for approval and could result in delay of the customers' planned in-service dates. For the remaining substations in the Apex Area Master Plan, the Companies request approval to perform an area constraint study, environmental studies, permitting and land acquisition as required to support area development.

Budget and Cost Responsibility: The Companies will be responsible for the costs for Apex Central 230/12 kV substation, and the Apex Central – Prospector 230 kV line. Subject to Rule 9 and the S/HVD, the Companies will be responsible for an estimated $15 million of the estimated $25 million project cost of Apex East 230/12 kV substation. Completion of the Apex Area Master Plan, as currently defined, is estimated to cost $121.87 million, but the initial request is approval of $77.3M for the initial phase of the project.

Construction Scope: The Apex Central substation will initially include two 230 kV breakers, one 230/12 kV 33 MVA transformer and all equipment required to energize the substation including steel structures, switches, bus work, relay protection and SCADA. The substation will be expandable to a breaker and a half configuration and can accommodate additional transformers and high-voltage distribution terminals in the future. The 230 kV Apex Central – Prospector line will include a new line terminal at Prospector and 6.4 miles of wire and required poles.
The Apex East substation will initially include three 230 kV breakers, one 230/12 kV 33 MVA transformer, which will be phased based on contractual load forecasts, and all equipment required to energize the substation including steel structures, switches, bus work, relay protection and SCADA. The substation will be expandable to a future breaker and a half configuration, and it will also be able to accommodate additional transformers and high-voltage distribution terminals in the future. The 230 kV fold of the Harry Allen – Pecos #2 230 kV line will include approximately 1.76 miles of wire and required poles.

For the future proposed Apex Southeast ("SE") and Apex Southwest ("SW") 230/12 kV substations, constraint study, environmental studies, permitting and land acquisition efforts will be initiated.

FIGURE TRAN-6
APEX CENTRAL SUBSTATION ONE LINE

NVEnergy	Apex Central 500/230/12 kV	7/24/2023

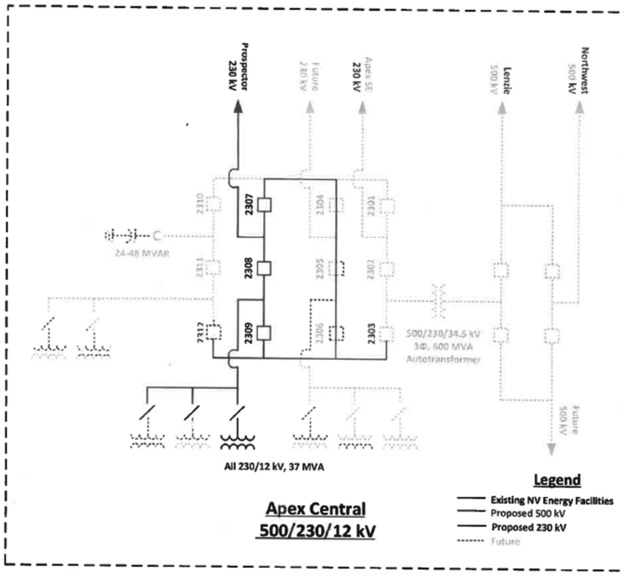


FIGURE TRAN-7
APEX EAST SUBSTATION ONE LINE

NVEnergy	Apex East 230/12 kV	6/29/2023

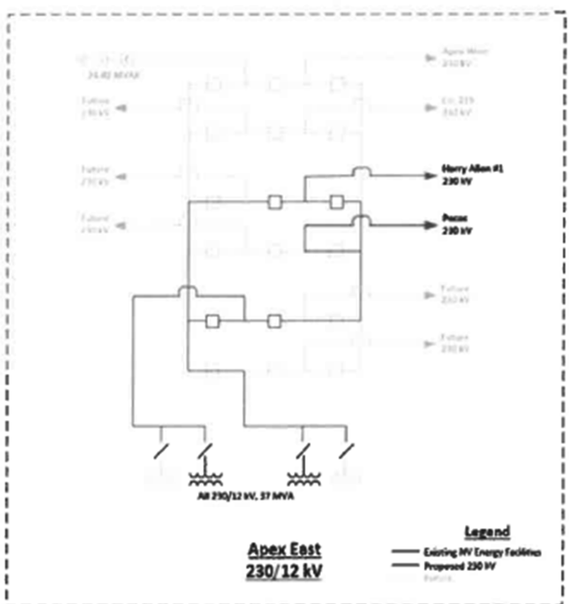


FIGURE TRAN-8
APEX AREA MASTER PLAN

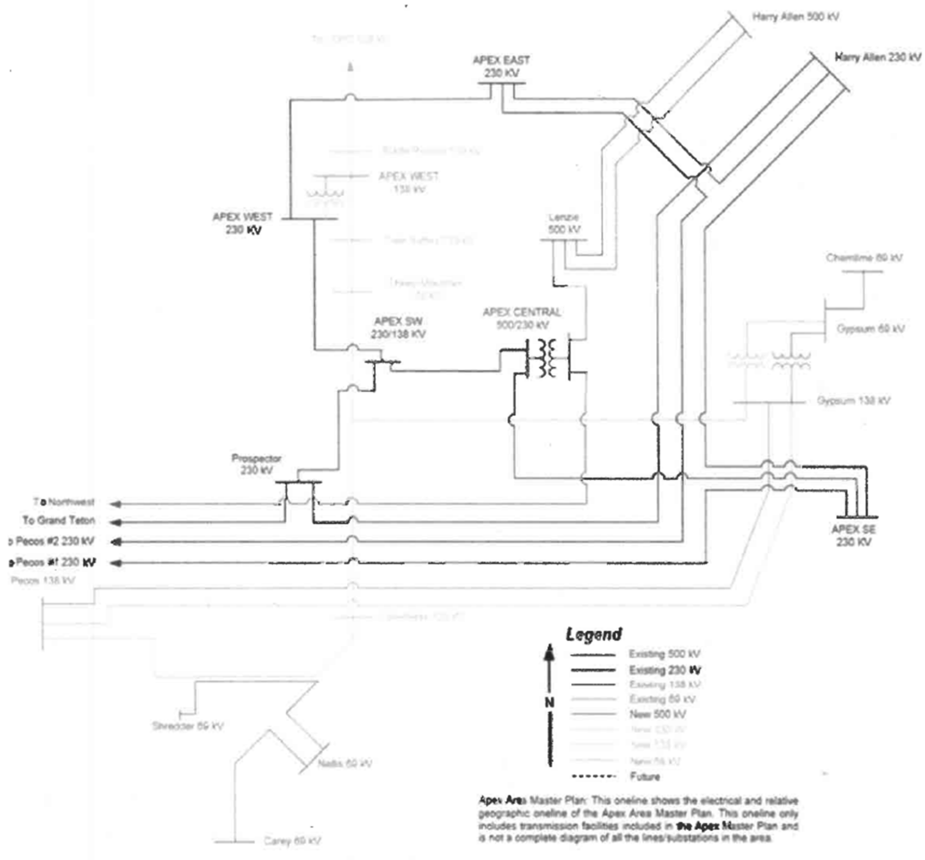


TABLE TRAN-3.1
APEX CENTRAL 230/12 KV SUBSTATION - CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
61.385	0.0	0.690	6.500	52.750	59.940	1.445

TABLE TRAN-3.2
APEX EAST 230/12 KV SUBSTATION - CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
15.500	0.0	0.200	0.600	14.600	15.400	0.100

TABLE TRAN-3.3
APEX SE 230/12 KV SUBSTATION - CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
0.221	0.0	0.036	0.185	0.0	0.221	0.0

TABLE TRAN-3.4
APEX SW 230/12 KV SUBSTATION - CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
0.168	0.0	0.042	0.018	0.108	0.168	0.0

TABLE TRAN-3.5
APEX AREA TRANSMISSION TOTAL CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
77.274	0.0	0.969	7.302	67.458	75.729	1.545

C. Informational

1. Greenlink Nevada Transmission Project Cost Update

Greenlink Nevada Transmission project has seen an overall cost increase in forecast of 17.8 percent from the original estimate prepared in 2019 and approved by the Commission in Docket Nos. 20-07023 and 21-06001. A summary of cost escalation is provided in the table below. The cost summary does not include the 230 kV buildout of Amargosa and Esmeralda substations that is being requested in this filing.

TABLE TRAN-4
GREENLINK PROJECT COST UPDATE

	Original Estimate as Approved	**July 2023 Update**	**Change ($)**	**Change (%)**
Greenlink West	$1,219.9m	$1,415.1m	$195.2m	16.1
Greenlink North	$854.1m	$1,050.6m	$196.5m	23
Common Ties	$410m	$461.5m	$51.5m	12.6
Total	$2,484m	$2,927.2m	$443.2m	17.8

2. Valmy Combustion Turbine ("CT") Lead Line Bus Position Construction

The Companies have identified two 200 MW CT units at Valmy in an alternative resource plan. The CT interconnection has not been studied by Transmission Planning, but if it were selected, it is assumed that, like the Valmy BESS, a 345 kV lead line bus would be constructed provisionally at North Valmy substation bus. An alternative worst case would be that a new line fold of the Valmy East Tracy #3421 345 kV line and new 345 kV substation may be required to interconnect the generators' lead line.

If the 200 MW Valmy BESS, the Valmy units' natural gas conversions and the two 200 MW CTs are constructed, then a remedial action scheme ("RAS") will be constructed for loss of certain 345 kV lines. This RAS would be called the Bell Boulder RAS and it would monitor and prevent an overload on the underlying Carlin Trend 120 kV system. It would monitor the 120 kV lines and open the 120 kV lines' parallel paths if overloads occur. This would eliminate the need to construct the Coyote Creek – Falcon 345 kV line for Valmy generation expansions for the foreseeable future. The Bell Boulder RAS would also eliminate the need for the previously proposed Valmy generation run-back RAS. The Bell Boulder RAS would also prevent loss of the load in the Carlin Trend for the aforementioned 120 kV line overloads. The Companies are not requesting approval of the 345 kV bus position and Bell Boulder RAS unless an alternative resource plan that includes the CTs is selected.

The CT units could be fast-start capable and therefore eliminate the need for the Valmy area must-run procedure discussed previously.

Budget and Cost Responsibility: The Companies will be responsible for the network upgrade cost of the 345 kV lead line bus position and the Bell Boulder RAS.

Construction Scope: The 345 kV bus position will include construction of all equipment and facilities required to accommodate steel structures, line breakers, switches, bus work, metering, relay, control building, protection, SCADA, and Bell Boulder RAS.

TABLE TRAN-5
VALMY CT LEAD LINE SUBSTATION CONSTRUCTION CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
36.626	0.0	0.00	0.00	0.00	0.00	36.626

3. North Valmy 345 kV BESS Lead Line Position Construction

The Companies have identified the Valmy BESS (Company PD) in an alternative Currently, there is a must-run operational requirement that a Valmy or Newmont generator must be running due to their 24-hour start-up times. If certain 345 kV contingencies occur, it is necessary to prepare the system for the next worst-case contingency. If the Valmy area generation is not running at the time of the contingency occurring, it would require load shedding until the generation was dispatched or the initial contingency is restored to normal operations. Also, based on the updated Valmy area transmission study, at system peak load without the generation running in the Valmy area, loss of 345 kV import paths will cause the transmission system to become unstable causing loss of generation and widespread customer outages of the north transmission system. In the transmission study, the loss of imports would simultaneously cause voltage collapse and insufficient generation resources in Sierra to replace the lost import.

Budget and Cost Responsibility: The Companies will be responsible for the costs for the 345 kV lead line bus position.

Construction Scope: The North Valmy 345 kV bus position will include construction of all equipment and facilities required to accommodate steel structures, line breakers, two bus breakers, switches, bus work, metering, relay, control building, protection, and SCADA.

TABLE TRAN-6
NORTH VALMY BESS LEAD LINE BUS POSITION CASH FLOW

Cash Flow ($MM)						
Project Total	Pre-2023	2023	2024	2025	3 Year Total (2023-2025)	Post 2025
10.2	0.0	0.00	1.00	9.2	10.2	0

4. Western Nevada Area Master Plan

The Companies are receiving significant load study requests between the Silver Springs substation and the Eagle Substation totaling 6,186 MW of new load at 11 sites by 2038. The existing large customers in the Tahoe Reno Industrial Complex are forecasting their loads to be 1,159 MW by 2038. Together, they total 7,345 MW that could be in addition to the normal incumbent load growth. These large customers create a unique opportunity and a challenge to meet this proposed load. It is not expected that all the loads will go forward but, to be prepared, the Companies have developed a flexible transmission plan that can be adapted as necessary to meet the customers' needs as the load evolves and develops over time. This new plan builds on the existing master transmission service plan for Tracy, Fernley & Fallon area (also known as the Tracy Area Master Plan) (Docket No. 22-11032 technical appendix TRAN-4). The difference between this plan and the previous Tracy Area Master Plan is the size of the plan, both geographically and size of the load. The intention of this expanded master area transmission plan is to make the most of the already planned transmission lines and minimize the impact of new lines by using already planned corridors for proposed transmission lines and substations. Currently, the Companies are not requesting approval of this plan but are submitting the plan to inform the Commission of the potential for extremely large load growth occurring in the next fifteen years.

SECTION 8. ECONOMIC ANALYSIS

A. Overview

As discussed in the Fourth Amendment to the 2021 Joint IRP ("Fourth Amendment") proceeding, this Fifth Amendment specifically addresses a complete solution to the timely retirement of coal combustion at Valmy and the need for voltage support and available around-the-clock generation in the Carlin Trend load pocket. In the 2021 Joint IRP, the Hot Pot and Iron Point PV/BESS projects were identified as the replacement for the coal-fired Valmy plant that provided both capacity and the identified system needs, while also contributing to the RPS. With the removal of these two projects from the Loads and Resources ("L&R") tables in the Fourth Amendment and the new requirement for around-the-clock generation to provide the transmission support for the Carlin Trend load pocket,[55] the Companies are proposing a new and complete replacement for the coal-fired Valmy plant as well as continuing the replacement for the RPS contribution expected from the Hot Pot and Iron Point projects.

The Fifth Amendment continues the evolution of Nevada's energy industry and market, addressing the need for a complete solution at Valmy, persistent concerns about the uncertain availability of regional market capacity, and incremental cancellations and a delay of previously approved renewable projects. This amendment prioritizes resource adequacy in reducing the Companies' open capacity position. "Open position" refers to the portion of the utility's capacity needs that are not met by resources under utility ownership or long-term contract. The Companies are prioritizing resource adequacy by adding new resources within their balancing authority area ("BAA"), thus reducing reliance on the external market. This amendment also proposes the economic continued operation of existing resources.

A stakeholder briefing was conducted to inform interested parties on the general content of this amendment. The notice for the meeting is contained in Technical Appendix ECON-1.

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

- Economic Analysis Methodology;
- Updates to Key Modeling Assumptions;
- Assessment of Need;
- Plan Development;

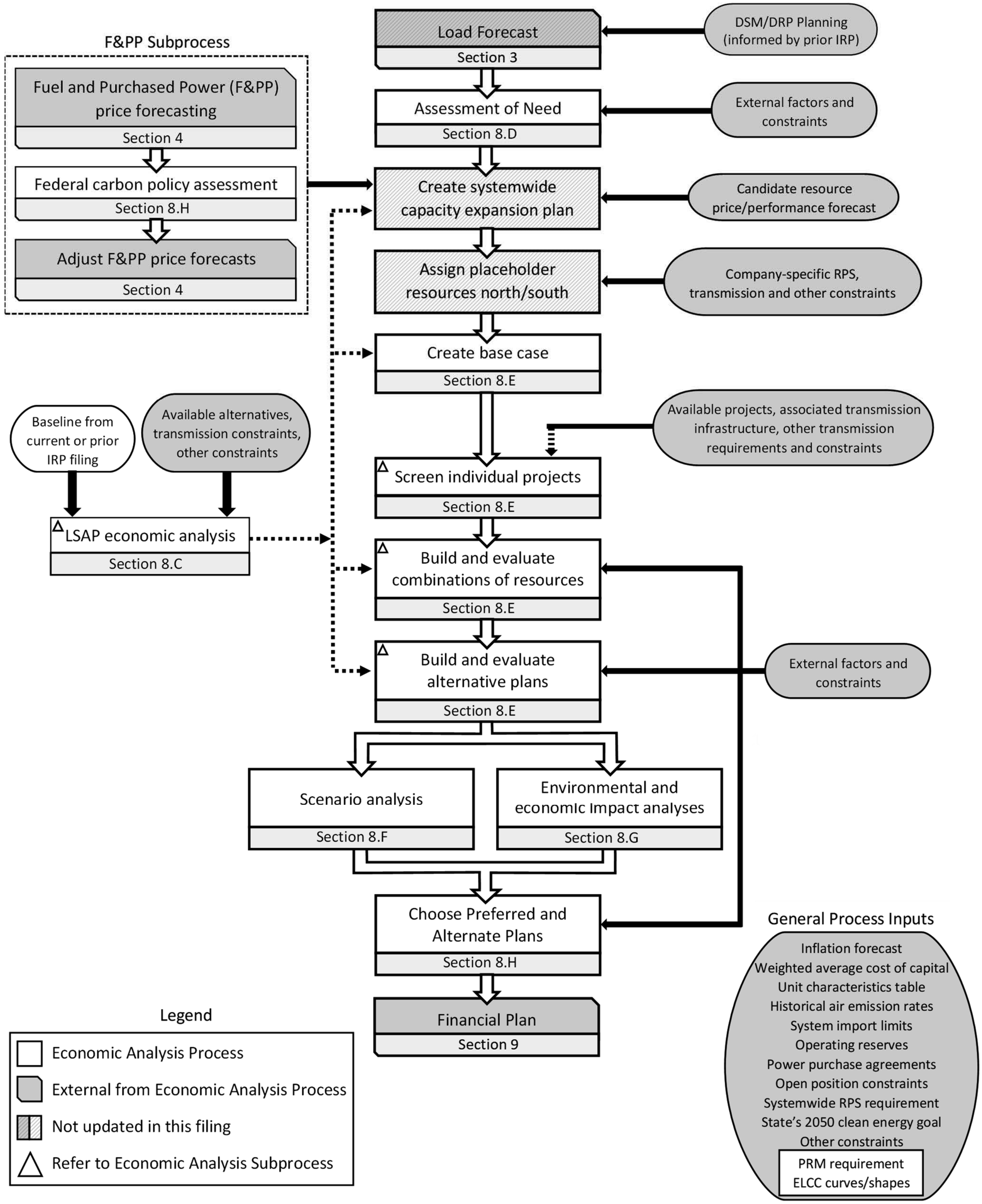
[55] *See* Transmission Section.

- Economic Analysis Results;
- Loads and Resources Tables;
- Environmental Externalities and Economic Benefits to the State; and
- Selection of the Preferred Plan.

B. Economic Analysis Methodology

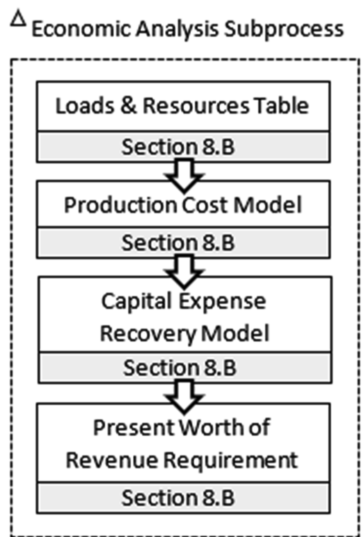
To aid in understanding the economic analysis performed for this amendment, an overall flowchart of the methodology is provided here for reference. This flowchart, Figure EA-1, is intended to supplement the narrative. It is generic and generally applicable to all IRPs, but some details may vary from filing to filing as dictated by different circumstances. As this filing is an amendment, rather than a full IRP, certain aspects of typical IRP's economic analysis process flow were not required. Those items are indicated with hash marks in the process flow diagram. The steps in the flowchart include references to locations in this narrative as a guide to the reader.

FIGURE EA-1
OVERALL WORKFLOW DIAGRAM OF ECONOMIC ANALYSIS METHODOLOGY



Please note some of the steps in the process flow diagram include a small triangle within the box. This triangle indicates the step requires a more detailed subprocess consisting of developing one or more L&R tables, production cost model runs, capital expense recovery ("CER") models, and present worth of revenue requirement ("PWRR") comparisons. A diagram of this subprocess follows.

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



This subprocess is repeated for multiple cases, and more detailed descriptions of each of these specific analysis steps are provided in the remainder of this subsection.

L&R Tables. The Companies' analysis of any specific plan begins with the development of the Loads and Resources table. The long-term load forecast, planning reserve requirements, and a forecast of an annual peak capacity for supply-side and demand-side resources are used to determine the Companies' annual 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.

For the forecasted annual capacity for supply side resources in the Fourth Amendment, as in the 2021 Joint IRP, the Companies used the software tool PLEXOS LT in development of long-term plans with future placeholder resources to fill the open position. As this amendment does not include an updated load forecast, no new capacity expansion plan was developed. Instead, a revised Fourth Amendment preferred plan was used as the starting point for the capacity expansion plan for this amendment. A detailed description of the revised Fourth Amendment plan is provided in subsection E.

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 subsection I of this Economic Analysis Section.

Production Costs and CER Models. After developing an L&R table, the Companies utilize additional software tools to evaluate each plan over the planning period. The first is a production cost model known as PLEXOS ST ("PLEXOS").[56] PLEXOS computes overall production cost by performing hourly, chronological economic unit commitment and dispatch of the Companies' electric production resources and market purchases to satisfy load requirements in a least-cost solution over the planning period. A more detailed description of PLEXOS can be found in Technical Appendix ECON-2. There are several key modeling assumptions made in performing PLEXOS analyses. Key assumptions, including updates from the assumptions used in the Fourth Amendment, are discussed in more detail in the next section. The key assumptions include, but are not limited to:

a) Study Period;
b) Area configuration;
c) Hourly load forecast;
d) Market fundamentals including fuel and purchased power forecasts of costs;
e) Existing generation operating characteristics and costs;
f) Operating reserves;
g) Planning reserves;
h) Life Span Analysis Process ("LSAP");
i) Effective Load Carrying Capability ("ELCC");
j) Power purchase agreements – including renewables;
k) Battery modeling;
l) Transmission limits; and
m) Resource buildouts.

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

a) Capital costs of new generation;

[56] NV Energy personnel briefed the Commission Staff and Bureau of Consumer Protection personnel on the transition from the PROMOD production cost modeling software to PLEXOS ST in a Teams meeting on June 29, 2023.

b) Capital costs of resource acquisitions;
c) Capital costs of transmission projects;
d) Construction cost escalation rates;
e) Cash flow schedules;
f) AFUDC estimates;
g) Construction start dates;
h) Project in-service dates;
i) Project book lives; and
j) Project tax lives.

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

C. Updates to Key Modeling Assumptions

Study Period. The study period for this Fifth Amendment is from 2024 to 2051 or for an overall look of 28 years. This period captures the remaining years previously considered in the 2021 IRP study period.

Area Configuration. The area configuration refers to how the BAA and external markets are represented in PLEXOS. A zonal model is used, and the configuration has not changed from the one used in the Fourth Amendment. The purpose of the zonal model is to simulate transmission between areas. However, PLEXOS is not an AC power-flow transmission model and the transmission flows determined by PLEXOS are based on economics. PLEXOS zonal tie flow outputs do not represent actual transmission line flows. A graphical depiction of the area configuration used in this filing, along with the 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 the same forecast approved in the Companies' Third Amendment to the 2021 Joint IRP ("Third Amendment"), Docket No. 22-09006.

Market Fundamentals. The Companies' forecasts of fuel and purchased power prices have been updated from the forecasts presented in the Fourth Amendment. As described in Section 1, Introduction, of the narrative, the Companies have experienced upward pressure on the cost to acquire and deliver coal to Valmy. Due to that experience, the Companies elected to use the high-level coal price forecast in the base and high fuel price scenarios. The mid-level coal price forecast was used for the low fuel price scenario. Details on these forecasts can be found in the Fuel and Purchased Power Price Forecasts Section.

Existing Generation Operating Characteristics, Costs and Continued Operation. Most operating characteristics assumptions, including fixed operations and maintenance ("O&M") of the Companies' generation fleet are shown in confidential Technical Appendix GEN-1. In this Fifth Amendment, the start costs of the Companies' generating units were based on the number of starts rather than the expected annual output of the units beginning in 2025. This change largely impacted the combined-cycle fleet. The change was made to account for additional maintenance on the generating fleet needed to accommodate dispatch-limited resources.

LSAP. Also included in this amendment, as mentioned in the Generation Section, is a request for continued operation of the Valmy Generating Station and the combined-cycle units referred to as Tracy Units 4 and 5 ("Tracy 4/5"). More information pertaining to the continued operation of existing generators can be found in subsection E, Plan Development, of this Economic Analysis and the LSAP discussion of the Generation Section. Note that, as illustrated in the workflow diagram in subsection A, the economic analysis for a particular LSAP can occur at different places in the overall economic analysis process flow, depending on the circumstances. For example, in the Fourth Amendment, multiple existing turbines were subject to LSAP evaluation with the result that it was determined to be economic to continue operation of all of them. Since continuing operation of so many units would have a substantial impact on the decades-long capacity expansion plan, it was appropriate to incorporate the economic continued operation of these units in the initial capacity expansion plan modeling performed for the filing. Thus, in the Fourth Amendment, the LSAP analysis preceded the capacity expansion plan modeling. In this Fifth Amendment, as described in subsection E, the result of the recent transmission study described in the Transmission Section triggered a need to perform the Valmy LSAP before a base case could be developed in order to ensure that the base case addressed the system needs in the Carlin Trend load pocket. If the base case did not address this requirement, it would be infeasible. The base case is used in the relative comparison performed for the economic impact analysis described in Subsection H. On the other hand, the Tracy 4/5 LSAP analysis was not required for development of the base case and does not impact the selection of near-term projects, thus it was incorporated later in the process, in the creation of the alternative plans.

Operating Reserves. As a BAA, the Companies carry sufficient operating reserves to comply with Western Electricity Coordinating Council and North American Electric Reliability Corporation standards. Operating reserves include a contingency reserve requirement, a portion of which is spinning reserve (spare online capacity), and a regulating reserve requirement. In this Fifth Amendment, the model of contingency reserve was updated so Nevada Power and Sierra would each carry a load-ratio share of the total contingency reserve requirement. This update better replicates actual operating practices. The model of regulating reserve was unchanged. Either Nevada Power, Sierra, or both utilities can provide the required regulating reserves.

Planning Reserves. In the 2021 Joint IRP, the Commission approved a 16 percent planning reserve margin ("PRM") for the Companies' capacity planning purposes. This is an installed capacity, or ICAP PRM, designed to be used with rated capacities for firm resources and ELCC[57] for dispatch-limited resources. In this Fifth Amendment, the Companies continue to use the 16 percent PRM and decrease their available resources by 90 MW. As described in subsection A, the 90 MW approximates reserves needed for OATT customers, or unbundled customers. Each utility is assumed to carry a load ratio share of the total 90 MW needed for the BAA.

ELCC. The Companies continue to use the ELCC curves and surfaces quantified in the ELCC study.[58] The study quantified the effective capacity value of the Companies' resource portfolio and provided ELCC curves for different types of dispatch-limited resources that captured how their effective capacity changes as a function of their penetration. An ELCC "surface" was created for solar and storage to allow the Companies to account for the interactive effects between solar and storage. The scope of the ELCC study – and subsequent PRM study – was designed to allow the outputs to remain useful over a period of time even as the portfolio and load forecast changes. The use of ELCC curves and surfaces, which relate the capacity value of each resource to its penetration on the grid rather than point estimates, allows the Companies to capture the saturation effects that occur as the penetration of individual resources increase over time.

Power Purchase Agreements – including Renewables. Existing PPAs are modeled in accordance with the terms of each contract. The Companies continue to model renewable resources as must-take agreements and to use ELCC to assign the effective capacity values associated with renewable resources.

Battery Modeling. Modeling of battery storage systems has changed from the Fourth Amendment. Battery storage systems can be directly modeled in PLEXOS. This enhancement to the input assumptions allows a more precise dispatch of battery resources based on economics and allowable cycles per year.

The model of paired PV and battery resources has changed from the methods used in previous amendments. PLEXOS allows for the model of the PV resource separate from the battery with a constraint to require the battery to be charged solely by the associated PV resource and a constraint to limit the total paired facility output, so it does not exceed inverter or transmission limits. This enhancement allows a more precise dispatch of battery resources based on economics and allowable cycles per year.

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

Carbon Emissions Impact Modeling. The assumptions for allowance prices for carbon dioxide emissions are the same as those used for the Fourth Amendment. That is, allowance prices are not included in the production cost model. The social costs of carbon due to carbon dioxide emissions are included in the societal cost analyses. Information on the modeling of the impacts of climate policy on fuel prices is provided in the Fuel and Purchased Power Price Forecast Section of this narrative. Information on the social cost of carbon is included in subsection G, Externalities and Net Economic Benefits.

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 PLEXOS is not an AC power-flow transmission 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. In previous filings, the Companies created a work-around to allow the PROMOD model to solve when must-take generation exceeded load requirements. This work-around is not required in PLEXOS. When must-take energy exceeds load requirements, the excess is labeled *dump* energy. Dump energy may also be referred to as overgeneration, curtailed energy, or excess energy.

Future Resources. As this amendment does not include an updated load forecast, no new capacity expansion plan was developed. Instead, a revised Fourth Amendment preferred plan was used as the starting point for the long-term portfolio for this amendment, with certain adjustments including incorporation of changes specified in the Commission's May 12, 2023, Order in the Fourth Amendment.

As in recent IRP filings, future firm dispatchable generation (also referred to as "firm dispatchable placeholders") are intended to represent low-carbon emitting technologies that can supply electricity reliably on demand for hours, days, or weeks at a time, but are not intended to represent any particular technology. The Companies are not requesting approval to acquire or build any firm dispatchable placeholder resources, and placeholder resources are subject to change in future filings. Additional information for firm dispatchable build options can be found in the Candidate Resource discussion in Technical Appendix ECON-10.

Similarly, future renewable resource additions (also referred to as "renewable placeholders") are included as needed to serve new load and to ensure compliance with the requirements of Nevada's RPS. To ensure the Companies exceed the RPS requirements in the planning process, renewable resources are added using an energy basis rather than a credit basis. That is, the renewable buildout does not account for banking of excess renewable credit.

The Companies are not requesting approval to acquire or build any renewable placeholder resources, and placeholder resources are subject to change in future filings. Placeholder renewables are assumed to be solar PV systems, BESS, wind, or geothermal resources. The Companies are not suggesting these types of renewable resources are the only ones that will be considered to fulfill future needs. Additional information for build options can be found in the Candidate Resource discussion in Technical Appendix ECON-10.

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, effects of tax credits, and project book lives and tax lives are all factors into the final annual revenue requirement that is included in the PWRR calculation.

Note that, for all CER analyses conducted, the Companies assumed a capital expenditure for the Apex Area Master Plan which is larger than described in the Transmission Section due to timing of the performance of the economic analysis. This larger amount is constant in all cases and plans and has no impact on the analyses or the selection of one plan over another. In summary, while the requested approval for a portion of the Apex Area Master Plan described in the Transmission Section and specified in Section 2 matches the amounts reflected in the Financial Plan, a larger amount was modeled in the economic analysis.

CER analysis can be found in Technical Appendices ECON-6 and ECON-7.

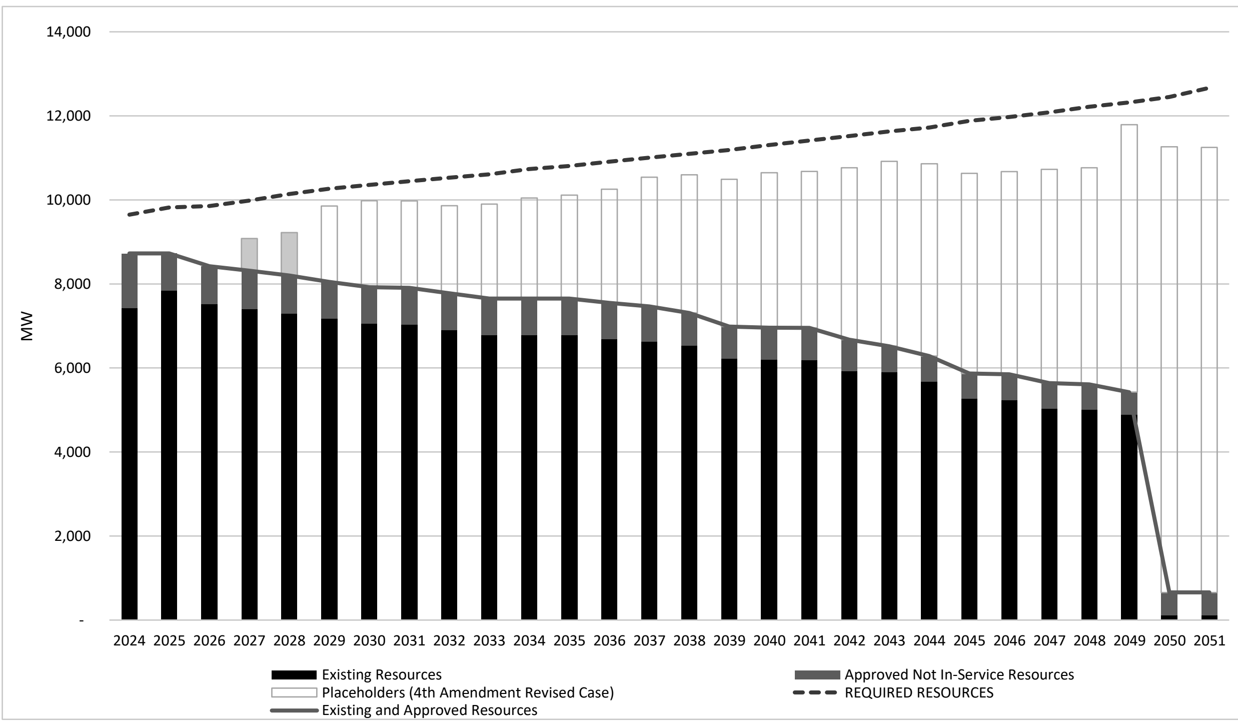
D. Assessment of Need

The Companies consider many factors to assess the resource needs over the amendment study period. In this amendment, the Companies considered the resource requirements associated with the retirement of the coal-fired Valmy plant, changes in capacity position related to changes to the retirement dates of existing resources, and the inability of some previously-approved renewable resources to meet their proposed commercial operation dates at the contracted price. Since these resources were expected to contribute to NV Energy's RPS, the Companies also had to assess if additional resources were needed to replace the PCs expected from these generators.

A revised Fourth Amendment preferred plan was used as the starting point for the capacity expansion plan for this amendment, with certain adjustments including incorporation of changes specified in the Commission's May 12, 2023, Order in the Fourth Amendment. Additionally, as described more fully in the Renewables Section, Southern Bighorn Solar and Chuckwalla renewable projects have been removed from the list of existing resources and the commercial operation date for Boulder Solar III has been delayed by a year and a half.

Figure EA-3 shows the Companies' capacity position with the assumptions stated above. The figure shows the system capacity requirements (loads plus PRM and reserves for OATT customers), existing resources (owned resources and those under contract and in service), resources approved but not in service (less Southern Bighorn Solar, Chuckwalla), and placeholder resources. The figure incorporates the delayed commercial operation date for Boulder Solar III. The Third Amendment base load forecast was used. Thermal units are shown at their peak capacities while renewable units have been adjusted for their ELCC. This is consistent with the use of an ICAP PRM as described previously.

FIGURE EA-3
NV ENERGY CAPACITY POSITION



The gap between the required resources (dashed line) and the stacked bar chart represents the open position for NV Energy. The light grey bars represent placeholder resources – potential future resources that have not been specifically identified. The gap between the required resources (dashed line) and existing and approved resources (solid line) represents the amount of capacity that must be procured from the market, filled with resources proposed in this Amendment, or filled with resources proposed in future IRP filings. Due to concerns about the availability of market capacity and energy, it is important to secure additional resources now. A portion of these new resources must be located within Sierra's transmission system because of Sierra's limited import capability. This requirement is especially true for the replacement of Valmy capacity. As discussed in Section 1, reducing the open position and replacing placeholders with specific resources is consistent with resource sufficiency requirements in WRAP, as well as the expected requirements of a potential future market or RTO.

A portion of the capacity need is due to the expected retirement of the Valmy Generating Station. This coal-fired generating station provides about 261 MW of capacity to NV Energy and provides transmission support in the Carlin Trend area. Due to the Sierra's limited import capability, a replacement for this capacity must be in Sierra's transmission area and must be in service before the Valmy units can retire. Additionally, the new transmission study described in the Transmission Section indicates PV or BESS resources alone would no longer be adequate to meet the system requirements for the Carlin Trend load pocket throughout the planning horizon of this amendment. The study now shows generation at or near Valmy must be running or able to start quickly to prevent low-voltage conditions given certain transmission outages at least until Greenlink West is in service. This generation must be available at any time and must continue until the outage is corrected. After Greenlink West is in service, the requirements for generation at Valmy may be relieved, dependent on load growth. These updated requirements prompted the Companies to re-evaluate potential resource needs at or near Valmy and triggered an LSAP for the existing Valmy units.

As discussed earlier in the subsection, two additional renewable resource projects, Southern Bighorn and Chuckwalla, have been removed from the Companies' L&R and the commercial operation of another, Boulder Solar III, has been delayed as more fully described in the Renewables Section. Delays, shortfalls, and/or cancellations of any renewable resources currently under development shorten the time period of the Companies' forecasted RPS compliance.

In summary, to continue reliably serving load in Nevada, the Companies need to:

- Allow for the timely retirement of coal-fired generation at Valmy with sufficient resources to continue the meet the voltage support and available around-the-clock generation requirement in the Carlin Trend area. An LSAP of the Valmy units was completed to analyze appropriate options for the replacement;
- Reduce the reliance on uncertain market availability and deliverability by adding new capacity, some of which must be located in northern Nevada; and,
- Replace some portion of the renewable portfolio to ensure adequate resources are available to maintain compliance with the RPS.

E. Plan Development

NAC § 704.937(1) requires a supply plan contain a "diverse set of alternative plans, which include a list of options for the supply of capacity and electric energy."

NRS § 704.741(3)(c) contains a requirement for a scenario of low carbon dioxide emissions in triennial Integrated Resource Plans submitted on or before June 1, 2027, that "uses sources of supply that result in, by the year 2030, an 80 percent reduction in carbon dioxide emissions from the generation of electricity to meet the demands of customers of the utility as compared to the amount of such emissions in the year 2005," while also meeting the state's 2050 clean energy goal and including the deployment of distributed generation. The July 13, 2022, order in the First 2021 IRP Amendment specified inclusion of this newly defined scenario in all amendments with supply-side scenarios submitted on or before June 1, 2027, but only required this requirement be met once every 12 months.[59] As such a plan was included in the Fourth Amendment filed in November 2022, a plan that meets this requirement is not required for this Fifth Amendment.

To facilitate the development of diverse supply plans to address the needs identified in the previous subsection, an updated version of the Fourth Amendment preferred plan was created, incorporating the retirement dates dictated in the Commission's Order in the Fourth Amendment, updated unit characteristics, updated fuel and market prices, and adjustments to approved resources as previously described. Near-term placeholders, those occurring before 2027, were removed from this case reflecting the change in NV Energy's expectation of future resource availability. The plan was designed to achieve the state's 2050 clean energy goal for NV Energy – an amount of energy production from zero carbon dioxide emission resources by 2050 that is equal to the total amount of electricity sales. This updated case includes the continued operation of the following existing generating units as approved in the Fourth Amendment in addition to those in the 2022 Sierra Electric Depreciation filing:[60]

1. Clark Generating Station Unit 4 through 2035
2. Clark Generating Station Units 5, 6, and 10 through 2044
3. Clark Generating Station Units 7, 8, and 9 through 2043
4. Clark Peakers through 2049
5. Harry Allen Generating Station Unit 3 through 2046
6. Harry Allen Generating Station Unit 4 through 2046
7. Harry Allen Generating Station combined-cycle units through 2049
8. Chuck Lenzie Generating Station through 2049
9. Silverhawk Generating Station through 2049
10. Higgins Generating Station through 2049
11. Las Vegas Generating Station through 2049
12. Sun Peak Generating Station through 2041
13. Clark Mountain units through 2044.

The workflow diagram shown in Figure EA-1 is a generic representation of the tasks needed to complete the economic analysis that includes indication of steps not used in this Amendment. Specifically in this amendment, the Companies followed the outline below in the development of alternative plans.

[59] Docket No. 22-03024, July 13, 2022, Order at 8, para. 6.
[60] Docket No. 22-06015.

- Update the preferred plan from the Fourth Amendment – *for this Amendment, this step replaces steps "Create Systemwide Capacity Expansion Plan" and "Assign Placeholder Resources north/south" in the workflow diagram*
    - Key assumptions discussed in subsection C
    - Existing unit retirement dates as approved in Fourth Amendment
    - Resources as approved in Fourth Amendment
    - Previously-approved projects that cannot meet their in-service dates at proposed price
- Develop Base Case
    - Conduct Valmy LSAP
    - Choose best option from Valmy LSAP
- Screen Individual Projects
    - Introduce potential projects individually in Base Case
    - Adjust placeholders in Base Case as needed
    - Conduct economic analysis (L&R, PLEXOS, CER, PWRR) for each case
    - Eliminate cases if appropriate
- Build and Evaluate Combinations of Resources
    - Introduce combinations of potential projects in Base Case
    - Adjust placeholders as needed
    - Conduct economic analysis (L&R, PLEXOS, CER, PWRR) for each case
    - Eliminate cases if appropriate
- Conduct Tracy 4/5 LSAP
- Build and Evaluate Alternative Plans
    - Select from combinations cases
    - Incorporate best option from Tracy 4/5 LSAP
    - Adjust placeholders as needed
    - Conduct economic analysis (L&R, PLEXOS, CER, PWRR) for each plan

Fourth Amendment Revised Case. This case assumes all projects approved in the Fourth Amendment, the removal of Southern Bighorn and Chuckwalla projects and delayed in-service date for Boulder Solar III as described in the Renewables Section, and includes the base load forecast from the Third Amendment. This case also assumes placeholder resources are not available before 2027. The detailed Fourth Amendment Revised Case buildout is shown in Figure EA-4.

FIGURE EA-4
BUILDOUT FOR FOURTH AMENDMENT REVISED CASE

	Fourth Amendment Revised Case	
	Sierra	Nevada Power
2026		
2027	350 MW PV - paired_27 300 MW BESS - paired_27	450 MW PV - paired_27 150 MW BESS - paired_27
2028		230 MW PV - paired_28 270 MW BESS - paired_28
2029	600 MW BESS - alone - SPPC_29	230 MW PV - paired - NPC_29 200 MW BESS - paired - NPC_29 400 MW BESS - alone - NPC_29
2030	290 MW PV - alone - SPPC_30	1180 MW PV - alone - NPC_30
2031		
2032		110 MW PV - alone_32
2033	210 MW PV - alone - SPPC_33	840 MW PV - alone - NPC_33 100 MW WIND - NV/AZ_33
2034	300 MW WIND - NV/AZ - SPPC_34	300 MW WIND - NV/AZ - NPC_34
2035		130 MW PV - alone_35 230 MW WIND - NV/AZ_35
2036	100 MW PV - alone - SPPC_36	380 MW PV - alone - NPC_36 380 MW BESS - alone_36
2037	460 MW BESS - alone - SPPC_37	400 MW PV - alone_37 250 MW BESS - alone - NPC_37
2038	400 MW PV - alone - SPPC_38	400 MW PV - alone - NPC_38 100 MW WIND - NV/AZ_38 140 MW BESS - alone_38
2039	280 MW PV - alone - SPPC_39 180 MW BESS - alone - SPPC_39	280 MW PV - alone - NPC_39 180 MW BESS - alone - NPC_39
2040		400 MW PV - alone_40 350 MW BESS - alone_40
2041		290 MW PV - alone_41
2042	480 MW PV - alone_42	900 MW BESS - alone_42
2043	580 MW BESS - alone_43	850 MW PV - alone_43
2044	180 MW PV - alone - SPPC_44	720 MW PV - alone - NPC_44 350 MW BESS - alone_44
2045	300 MW WIND - ID_45	230 MW PV - alone_45 350 MW BESS - alone_45
2046		800 MW PV - alone_46
2047		900 MW PV - alone_47 550 MW BESS - alone_47
2048		1050 MW PV - alone_48
2049	900 MW Firm_dispatchable_NN_49	1150 MW PV - paired_49 1600 MW BESS - paired_49
2050	450 MW Firm_dispatchable_NN - SPPC_50 450 MW PV - alone_50	450 MW Firm_dispatchable_SN - NPC_50 2250 MW Firm_dispatchable_SN - NPC_50 3000 MW PV - paired_50 3000 MW BESS - paired_50

Note that the Fourth Amendment Revised case does not address the voltage support and available around-the-clock generation requirements in the Carlin Trend load pocket described in the Transmission Section. Therefore, this case is not one the Companies would implement, and is included only for use in development of the complete Valmy solution.

Valmy LSAP. The need for a complete solution at Valmy triggered the need to conduct an updated Valmy LSAP. A detailed description of the LSAP is included in the Generation Section. Briefly, there must be a replacement for some or all of the capacity of Valmy, in service at least coincident with Valmy's retirement, to meet load requirements and system requirements in the Carlin Trend. While there may be some flexibility in the source of replacement capacity for Valmy, the requirement for generation identified in subsection A of the Transmission Section is restrictive. The requirements for generation to provide the Carlin Trend area system stability and voltage support as presented in the Transmission Section are:

- Generation must be at or near the existing Valmy Generating Station,
- Must be online (generating) or be able to start generating quickly, and
- Must generate continuously until a transmission outage is corrected.

PV generation cannot satisfy the system requirements because, if the transmission outage occurred or continued after the solar day, generation would not be available. BESS alone, or when paired with PV, also cannot satisfy the requirement because it may take more than 4 hours to correct the transmission outage, or the outage may occur when the BESS state of charge is low.

As described in the Transmission Section, the requirement for a generating asset at or near Valmy may be suspended once Greenlink West is in service. However, given certain outage conditions or if load growth exceeds the forecast level, the generation requirement may recur. The Valmy LSAP analysis considered several options to allow for the near-term retirement of coal combustion at Valmy.

The Companies modeled three near-term generating options to meet the system requirements and provide for capacity at the Valmy site. Description of these options follows.

> ***Repower Valmy.*** The Companies analyzed the repowering of the Valmy coal-fired boilers to combust only natural gas. Valmy Unit 1 would cease coal-fired generation after summer 2025 and be converted to natural gas combustion by December 2025. Valmy 2 would operate continuously during the repower of Valmy 1 to meet system needs. Valmy Unit 2 would cease coal-fired generation at the end of 2025, after the repowered Valmy Unit 1 is in service. Valmy 1 would operate continuously during the conversion of Valmy 2. Valmy 2 would be in service by summer 2026. The repowered units would be retired at the end of 2049. Although not modeled, if around-the-clock generation is required after Greenlink West is in service, the repowered Valmy units could again provide this service.

New CTs located at Valmy Generating Station. A new approximately 440 MW peaking plant of simple cycle gas turbines in service by summer 2027 was also analyzed as a replacement for Valmy capacity. These two new CTs would not be available soon enough to allow both Valmy units to cease coal-fired generation by the end of 2025. Continuous operation of one coal-fired Valmy unit would be required to address the system needs in the Carlin Trend until Greenlink West is in service. The coal-fired Valmy units would remain in service until the two CTs are placed in service and would be subsequently retired. As with the previous case, voltage support and available around-the-clock generation for the Carlin Trend could be provided by the CTs, if required, after Greenlink West is in service.

New PV/BESS generation located at Valmy Generating Station. A 350 MW PV with 350 MW of BESS project in service by summer 2026 was analyzed as a replacement for Valmy capacity. Because this new resource cannot provide the need for available around-the-clock generation, at least one coal-fired Valmy unit would be required to operate continuously to address the system requirements until Greenlink West is in service. The coal-fired Valmy units would retire once Greenlink West is in service. This option could not reliably supply system needs after the Valmy units' retirement if the generation requirement described in subsection A of the Transmission Section recurs.

Initial Valmy LSAP screening cases were developed by adding these projects individually to the Fourth Amendment Revised Case, adjusting placeholder resources to achieve similar open positions. Costs to supply natural gas to the Valmy site were included in appropriate cases.

The specific cases are briefly described as:

- ***Fourth Amendment Revised.*** Resources for this case are presented in Figure EA-4. As stated previously, this case does not address the voltage support and available around-the-clock generation requirement in the Carlin Trend load pocket described in the Transmission Section.
- ***Valmy Repower – Half.*** Both Valmy units will be repowered to combust only natural gas. The repower of the units will be staggered so at least one unit will be available at all times, with intent for the retirement of coal-fired generation at the end of 2025. Both repowered units will be available by summer 2026 and will retire at the end of 2049. The repowering of Valmy provides transmission support to the Carlin Trend area and satisfies must-run requirements at Valmy. The case assumes the Companies will share the cost and resulting capacity of the repowered Valmy units with the plant's co-owner, Idaho Power.
- ***Valmy Repower – All.*** Similar to the above case, except this case assumes the Companies will bear all costs associated with the repower and receive the full capacity from both Valmy Units. The repowering of Valmy provides transmission support to the Carlin Trend area and satisfies must-run requirements at Valmy.

- ***Valmy – 2 CTs.*** Two new natural gas fired peaking combustion turbines replace the existing Valmy units by summer 2027. This case requires the existing Valmy Units to continue operation on coal until the new CTs are in service. The new CTs will retire at the end of 2049. The coal-fired Valmy units satisfy the must-run requirements at Valmy until Greenlink West is in service. The new CTs provide replacement capacity and are redundant, fast starting capabilities provide ongoing transmission support in the Carlin Trend area. Risks surrounding continued combustion of coal at Valmy past 2025 are discussed in the Generation Section.
- ***Hot Pot.*** A new 350 MW PV project paired with 350 MW BESS located in the Valmy area in service in mid-2026. This is the Hot Pot project bid in the recent RFP as described later in the Individual Project Screening and in the Renewables Section. This case requires the existing Valmy Units to continue operation on coal until Greenlink West is in-service. The new PV and BESS will retire on May 30, 2056, and May 30, 2046, respectively. The coal-fired Valmy units will satisfy the must-run requirements at Valmy until Greenlink West is in service. Risks surrounding continued combustion of coal at Valmy past 2025 are discussed in the Generation Section. The new PV and BESS provide replacement capacity and transmission support in the Carlin Trend load pocket but cannot reliably provide that transmission support in all hours if generation is required, as discussed in the Transmission Section.

While the full Valmy LSAP discussion is presented in the Generation Section, the L&R tables for the Valmy LSAP analysis are provided in Technical Appendix ECON-5. The redacted cost summaries and load balances from the production cost model runs are included in Technical Appendix ECON-4. The CER analysis for each case is part of Technical Appendices ECON-6 and ECON-7.

The PWRR results of the economic analysis of the Valmy LSAP analysis are shown in Figure EA-5 below.

FIGURE EA-5
RESULTS OF VALMY LSAP SCREENING

	20 Year PWRR 2024-2043 (million $)	28 Year PWRR 2024-2051 (million $)	20 Year PWRR Change vs Least Cost Case (million $)	28 Year PWRR Change vs Least Cost Case (million $)
Updated 4th IRPA	$ 22,137	$ 28,627	$ 204	$ 320
Valmy 2-CTs	$ 22,037	$ 28,431	$ 104	$ 124
Valmy 2026 Repower - Half	$ 22,031	$ 28,458	$ 99	$ 152
Valmy 2026 Repower - All	$ 21,933	$ 28,307	$ -	$ -
Hot Pot	$ 22,479	$ 29,034	$ 547	$ 727

Key findings of Valmy LSAP analysis are provided below:

- As stated previously, the *Fourth Amendment Revised* (denoted as *Updated 4th IRPA* in the figure above) does not provide the transmission support needed in the Carlin Trend area after 2025.
- *Repower Valmy – All* is the least-cost case, primarily due to the low cost of the additional capacity at Valmy. However, as discussed in the Generation Section, the plant's co-owner is evaluating its interest in continuing its partial ownership of the repowered units. The conservative assumption is that only half of the repowered units would be available to the Companies.
- *Valmy 2-CTs* delays retirement of coal combustion at Valmy until the new CTs are built and requires must-run of at least one coal-fired unit to continue until Greenlink West is in service. Continued coal-fired operation is subject to environmental regulatory constraints, including limitations imposed by the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, as presented in the Generation Section. *Valmy 2-CTs* has relatively low operating costs, however, in this analysis, the lower operating costs are not sufficient to offset the high near-term capital costs needed to purchase and construct the CTs.
- *Repower Valmy – Half* has a higher PWRR than *Valmy 2-CTs* by less than one-tenth of one percent, allows for the retirement of coal-fired generation at Valmy and meets all the requirements for system support in the Carlin Trend load pocket.
- *Hot Pot* has the highest PWRR. It delays retirement of coal combustion at Valmy and requires must-run of at least one coal-fired unit until Greenlink West is in-service. Continued coal-fired operation is subject to environmental regulatory constraints, including limitations imposed by the Good Neighbor Plan, as presented in the Generation Section. This option provides the full around-the-clock transmission support in the Carlin Trend load pocket described in the Transmission Section only until Greenlink West is in-service and the Valmy units are retired. Subsequently, around-the-clock generation is not available at this location.

More discussion of the Valmy LSAP analysis can be found in the Generation Section.

Note that, the Companies anticipate the Valmy co-owner will continue participating in the units through the repowering on natural gas and subsequent continued operation as discussed in the Introduction Section. However, if the co-owner does not participate in the repower, it has been shown here to be cost effective for the Companies to complete the full Valmy repower, bearing all costs and receiving the full capacity of both repowered units.

Informed by the outcome of the Valmy LSAP analysis, the Companies adopted the *Repower Valmy – Half* case as the base case. This base case was used for the subsequent analysis of additional projects that could fill the near-term capacity and RPS needs discussed previously in subsection D.

This base case is chosen due to the Companies' desire to retire coal combustion, consistent with the state's objectives to continue advancing towards the state's 2050 clean energy goal, concerns about risks of continued coal-fired operation as described in the Generation Section, as well as the expectation that, in the event Valmy is repowered, the station's co-ownership would continue. This case provides the needed transmission support through the in-service date of Greenlink West and is capable of providing it after that time to fulfill potential future needs as described in the Transmission Section.

While the expected 2026 limitations of the U.S. Environmental Protection Agency's Good Neighbor Plan, as discussed in the Generation Section, did not prove constraining in the *Valmy 2-CTs* or *Hot Pot* cases when modeled with the base (normal weather) load forecast, concerns exist as to how constraining these limitations might prove to be in actual conditions. Extreme weather conditions or wildfires in summer 2026 could increase demand during the May through September ozone season, causing the rule's limitations on Valmy operation to become constraining.

The newly defined Base Case buildout is shown in Figure EA-6.

FIGURE EA-6
BUILDOUT FOR BASE CASE

	BASE	
	Sierra	Nevada Power
2026	261 MW Repower Valmy_26	
2027	350 MW PV - paired_27 300 MW BESS - paired_27	450 MW PV - paired_27 150 MW BESS - paired_27
2028		230 MW PV - paired_28 270 MW BESS - paired_28
2029	500 MW BESS - alone - SPPC_29	230 MW PV - paired - NPC_29 150 MW BESS - paired - NPC_29 500 MW BESS - alone - NPC_29
2030	370 MW PV - alone - SPPC_30	1100 MW PV - alone - NPC_30
2031		
2032		110 MW PV - alone_32
2033	210 MW PV - alone - SPPC_33	840 MW PV - alone - NPC_33 100 MW WIND - NV/AZ_33
2034	300 MW WIND - NV/AZ - SPPC_34	300 MW WIND - NV/AZ - NPC_34
2035		130 MW PV - alone_35 230 MW WIND - NV/AZ_35
2036	100 MW PV - alone - SPPC_36	380 MW PV - alone - NPC_36 280 MW BESS - alone_36
2037	280 MW BESS - alone - SPPC_37	400 MW PV - alone_37 280 MW BESS - alone - NPC_37
2038	400 MW PV - alone - SPPC_38	400 MW PV - alone - NPC_38 100 MW WIND - NV/AZ_38 140 MW BESS - alone_38
2039	280 MW PV - alone - SPPC_39 180 MW BESS - alone - SPPC_39	280 MW PV - alone - NPC_39 180 MW BESS - alone - NPC_39
2040		400 MW PV - alone_40 350 MW BESS - alone_40
2041		290 MW PV - alone_41
2042	480 MW PV - alone_42	900 MW BESS - alone_42
2043	580 MW BESS - alone_43	850 MW PV - alone_43
2044	180 MW PV - alone - SPPC_44	720 MW PV - alone - NPC_44 350 MW BESS - alone_44
2045	300 MW WIND - ID_45	230 MW PV - alone_45 350 MW BESS - alone_45
2046		800 MW PV - alone_46
2047		900 MW PV - alone_47 550 MW BESS - alone_47
2048		1050 MW PV - alone_48
2049	900 MW Firm_dispatchable_NN_49	1150 MW PV - paired_49 1600 MW BESS - paired_49
2050	450 MW Firm_dispatchable_NN - SPPC_50 450 MW PV - alone_50	450 MW Firm_dispatchable_SN - NPC_50 2250 MW Firm_dispatchable_SN - NPC_50 3000 MW PV - paired_50 3000 MW BESS - paired_50

Individual Project Screening. NV Energy compiled a list of potential resources that could fill the Companies' near-term need for additional capacity resources or renewable credits and capacity. As described more fully in the Renewables Section, the following projects were brought forth as resources that could fulfill the need for additional capacity and renewable credits: Sierra Solar PV/BESS, Valmy BESS, Iron Point PV/BESS, and Hot Pot PV/BESS. These resource options were developed from a combination of self-development efforts, RFP bid responses, and bilateral negotiations as described in the Renewables Section. Specifically, the Hot Pot and Iron Point projects evaluated here are responses from the recent RFP as described in the Renewables Section. In addition, the previously discussed two new CTs at Valmy were also considered as a viable project to meet the need for more capacity. Despite all being northern resources, these new, potential projects were each shared between Sierra and Nevada Power, as both Companies have a capacity need and Nevada Power's forecasted RPS non-compliance year is earlier than Sierra's as described in the Renewables Section.

Screening cases were developed by adding these projects individually to the Base Case, then adjusting placeholder resources to achieve similar open positions in each screening case.

The individual project screening cases are briefly described as:

- ***Base Case.*** Resources, which includes the Valmy repower, as previously presented in Figure EA-6.
- ***Valmy 2-CTs.*** Replaces Base Case placeholder resources with two 220 MW peaking turbines located at the Valmy site. The ownership of these units will be evenly split between the Nevada Power and Sierra. The units will be in service by summer 2027 and retire in 2049. The Valmy CTs provide a portion of the Companies' capacity need but do not add any contribution to the RPS need.
- ***Valmy BESS.*** Replaces Base Case placeholder resources with a 200 MW BESS project at Valmy. Ownership of the BESS will be evenly split between Nevada Power and Sierra. The project will be in service at the end of 2025. The Valmy BESS provides capacity to fill some of the Companies' capacity need sooner than any other project but does not directly contribute to RPS compliance.
- ***Sierra Solar.*** Replaces Base Case placeholder resources with 400 MW of PV paired with 400 MW BESS near Fernley, NV.[61] This project has a BESS in-service date in the summer of 2026 and a PV in-service date in spring 2027. This project will contribute to both Companies' RPS and capacity needs. Ownership is split 60 percent to Nevada Power and 40 percent to Sierra.
- ***Hot Pot.*** Replaces Base Case placeholder resources with the updated RFP bid for the Hot Pot project which consists of a 350 MW of PV paired with 350 MW BESS located in the Valmy area. This project has an in-service date of 2026 for both PV and BESS. The BESS

[61] As described in the Renewables Section, the Sierra Solar PV/BESS project was evaluated in the economic analysis at a higher cost for both the PV and BESS portions than the values requested for approval in this filing. In the economic analysis, the Sierra Solar costs for the PV and BESS components were each overstated by about $25 million.

analyzed in this project can be charged by the grid as opposed to by the PV unit only. In addition, this project contributes to both Companies' RPS and capacity needs. Ownership is split 60 percent to Nevada Power and 40 percent to Sierra.

- ***Iron Point.*** Replaces Base Case placeholder resources the updated RFP bid for the Iron Point project which consists of 250 MW of paired PV and BESS located in the Valmy area. This project has an in-service date of 2026 for both PV and BESS. The BESS analyzed in this project can be charged by the grid as opposed to by the PV unit only. In addition, this project contributes to both Companies' RPS and capacity needs. Ownership is split 60 percent to Nevada Power and 40 percent to Sierra.
- ***Hot Pot and Iron Point.*** A combination of the two projects listed above replaces Base Case placeholder resources. A different price for the PV generation was offered if both projects were taken. The in-service dates were to remain in 2026. Prices for the BESS were unchanged. These projects contribute to both Companies' RPS and capacity needs. Ownership is split 60 percent to Nevada Power and 40 percent to Sierra.

The L&R tables for the individual project screening are provided in Technical Appendix ECON-5. The redacted cost summaries and load balances from the production cost model runs are included in Technical Appendix ECON-4. The CER analysis for each case is part of Technical Appendices ECON-6 and ECON-7.

The PWRR results of the individual project screening analysis are shown in Figure EA-7 below.

FIGURE EA-7
RESULTS OF INDIVIDUAL PROJECT SCREENING

	20 Year PWRR 2024-2043 (million $)		28 Year PWRR 2024-2051 (million $)		20 Year PWRR Change vs Least Cost Case (million $)		28 Year PWRR Change vs Least Cost Case (million $)	
Base	$	22,031	$	28,488	$	147	$	265
Sierra Solar	$	22,073	$	28,531	$	189	$	308
Hot Pot	$	22,127	$	28,577	$	243	$	354
Iron Point	$	22,124	$	28,583	$	240	$	360
Hot Pot and Iron Point	$	22,403	$	28,887	$	519	$	664
Valmy BESS	$	21,948	$	28,354	$	64	$	131
2 Valmy CTs	$	21,884	$	28,223	$	-	$	-

Key findings of the individual projects screening are provided below.

- *Valmy 2-CTs* has the lowest PWRR. The case supplies a portion of the Companies' capacity need but none of the renewable credits. The dispatchable nature of the project provides energy and capacity when needed by the system with no excess, which contributes to the lower total cost of this case.

- *Valmy BESS* has the next lowest PWRR. Like the CT case, the Valmy BESS case fills a portion of the capacity need but does not supply any renewable credits. The Valmy BESS has a lower cost to operate and install than the placeholder it replaces.
- The three cases with individual paired solar and BESS projects– *Sierra Solar*, *Hot Pot*, and *Iron Point* – provide needed renewable credits, but due to the relatively low ELCC of solar, provide limited additional capacity.
- *Sierra Solar* has the lowest PWRR of the cases that add paired PV and BESS. Of the PV/BESS resources, Sierra Solar PV/BESS project has the lowest construction cost and the highest nameplate rating. Because the Sierra Solar project is owned by NV Energy, the cost of energy is assumed to be zero which keeps the production costs for this case low.
- The combined *Hot Pot and Iron Point* has the highest total PWRR.

<u>Combination Cases.</u> Based on the results of the individual project screening, the Companies developed another set of cases adding combinations of proposed resource options to the Base Case. Each combination case is described below.

- ***Repower Valmy + 2 CTs + SS + BESS.*** This case combines the repower of the Valmy units, the 2 CTs at Valmy, Sierra Solar PV/BESS, and the Valmy BESS. Repower Valmy, Sierra Solar BESS and Valmy BESS all have expected in-service dates in 2026. Sierra Solar PV and Valmy CTs have expected in-service dates in 2027.

- ***Repower Valmy + 2 CTs + SS.*** This case combines the repower of the Valmy units, the 2 CTs at Valmy, and Sierra Solar PV/BESS. Repower Valmy and Sierra Solar BESS both have expected in-service dates in 2026. Sierra Solar PV and Valmy CTs have expected in-service dates in 2027.

- ***Repower Valmy + SS + BESS.*** This case combines the repower of the Valmy units, Sierra Solar PV/BESS, and the Valmy BESS. Repower Valmy, Sierra Solar BESS and Valmy BESS all have expected in-service dates in 2026. Sierra Solar PV has an expected in-service date in 2027.

- ***Repower Valmy + SS.*** This case combines the repower of the Valmy units and Sierra Solar PV/BESS. Repower Valmy and Sierra Solar BESS both have expected in-service dates in 2026. Sierra Solar PV has an expected in-service date in 2027.

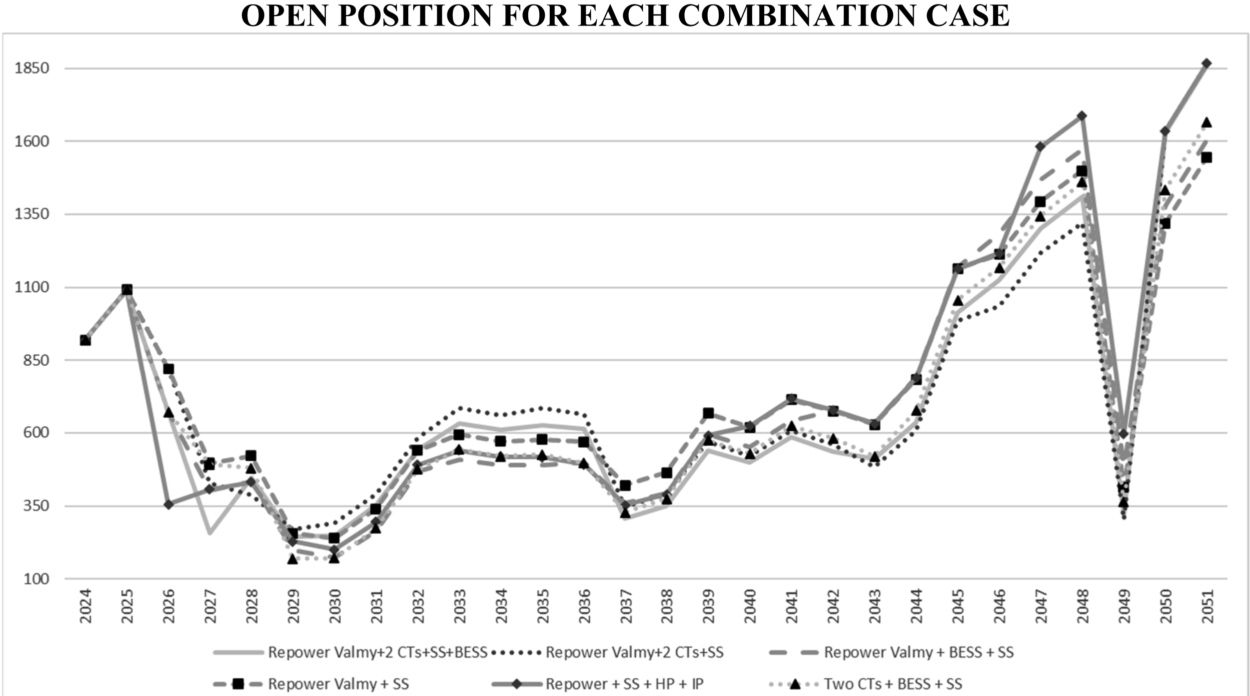
- ***Repower Valmy + SS + HP + IP.*** This case combines the repower of the Valmy units, Sierra Solar PV/BESS, updated Hot Pot PV/BESS bid, and updated Iron Point PV/BESS bid. Repower Valmy, the Sierra Solar BESS, Hot Pot, and Iron Point all have expected in-service dates in 2026. Sierra Solar PV has an expected in-service date in 2027.

- ***Valmy 2 CTs + BESS + SS.*** This case combines 2 CTs at Valmy, the Valmy BESS, and Sierra Solar PV/BESS. Valmy BESS and Sierra Solar BESS both have expected in-service dates in 2026. The 2 CTs and Sierra Solar PV both have expected in-service dates in 2027.

It is noteworthy that all of the combination cases include the Sierra Solar PV/BESS project, as it is the least cost of the PV/BESS project options. It adds diversity of supply as a renewable resource capable of providing energy during daytime, evening, and nighttime hours. It contributes to RPS compliance while also reducing the open capacity position via a large dispatchable BESS, larger than any BESS currently in NV Energy's portfolio, available in the net-peak evening hours after solar production has dropped off. The Sierra Solar project would help reduce dependency on fossil-fueled generation, providing price stability as it is unaffected by variable fuel costs. These characteristics of Sierra Solar meet the retail price stability and diversity of supply criteria for the critical facility designation under NAC § 704.9484(2).

Placeholder resources in these cases are adjusted ensure similar open positions between the cases. This adjustment is done to present cases with similar reliability. The open positions for the combination cases are shown in Figure EA-8. The placeholders assumed in each of these cases are provided in the respective L&R tables.

FIGURE EA-8
OPEN POSITION FOR EACH COMBINATION CASE



There is a significant change in open position in 2049 in all cases. This anomaly is caused by the method the Companies used in adding and removing capacity from the L&R tables. In a year when capacity is added, it is assumed to be available for the peak in that year. When capacity is removed (retired), it is also assumed to be available for the peak in the retirement year. As a very large amount of capacity retires in 2049, a large amount of replacement capacity was added in the form of new firm dispatchable units and renewable resources, targeting the Companies' share of the state's 2050 clean energy goal. The amount of available capacity in 2049 is overstated because of the timing of placeholders and capacity accounting used in the L&R table, causing a drop in open position. The sharp drop in open position will likely not occur.

Figures EA-9 and EA-10 are provided to further illustrate the placeholder differences between the cases in the early years, where they are most notable, and the later years, as a bookend.

FIGURE EA-9
PLACEHOLDER RESOURCES – COMBINATION CASES, 2027-2032

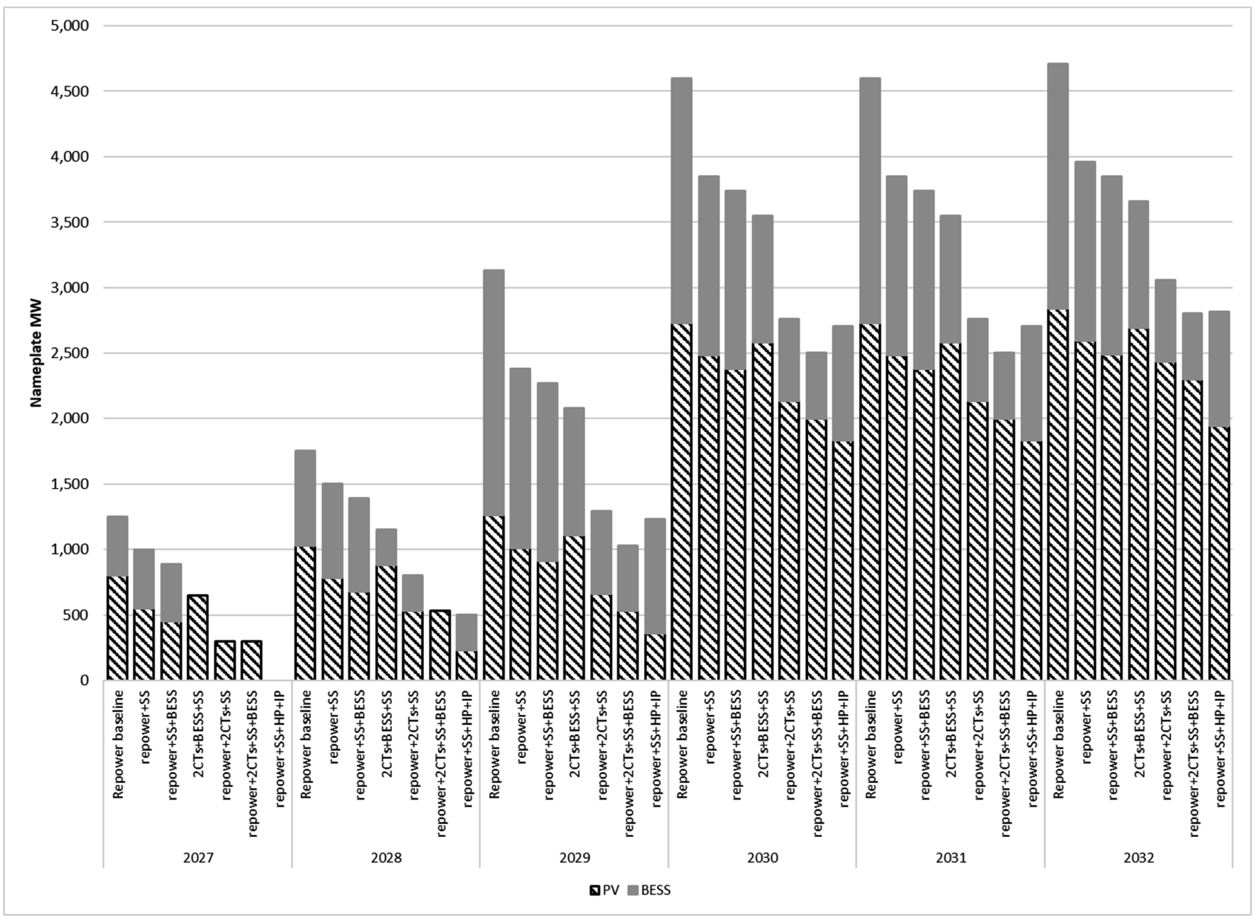
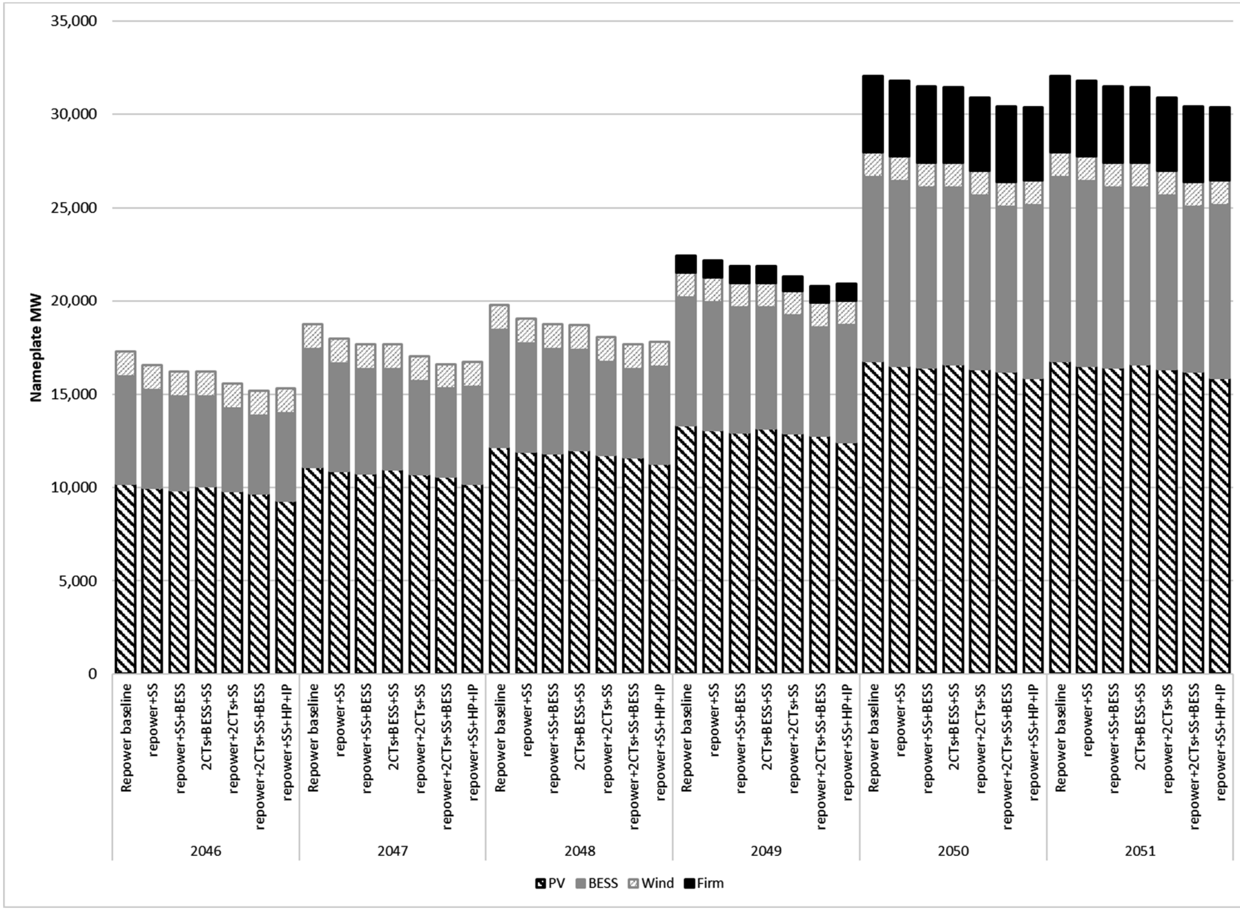


FIGURE EA-10
PLACEHOLDER RESOURCES – COMBINATION CASES, 2046-2051



The redacted cost summaries and load balances from the production cost model runs are included in Technical Appendix ECON-4. The CER analysis for each case is part of Technical Appendices ECON-6 and ECON-7.

The PWRR results of the combination case screening are shown relative to the Base Case (*Repower Valmy – Half*) in Figure EA-11.

FIGURE EA-11
RESULTS OF COMBINATION CASE SCREENING

	20 Year PWRR 2024-2043 (million $)	28 Year PWRR 2024-2051 (million $)	20 Year PWRR Change vs Least Cost Case (million $)	28 Year PWRR Change vs Least Cost Case (million $)
Valmy 2026 Repower - Half	$ 22,031	$ 28,488	$ 159	$ 303
Repower+2CTs+SS+BESS	$ 21,873	$ 28,185	$ -	$ -
Repower+2CTs+SS	$ 22,138	$ 28,560	$ 266	$ 375
Repower+BESS+SS	$ 22,197	$ 28,615	$ 324	$ 430
Repower+SS	$ 22,113	$ 28,576	$ 240	$ 390
Repower+SS+HP+IP	$ 22,314	$ 28,735	$ 441	$ 550
2CTs+BESS+SS	$ 22,259	$ 28,700	$ 386	$ 515

Note that the Base Case, *Repower Valmy – Half*, is a baseline for comparison in this analysis. It adds resources only to provide a complete Valmy solution and has the second lowest PWRR. It does not add proposed projects to push out the RPS compliance dates for the Companies, relying instead on placeholder renewable resources for this purpose. As shown in the Renewables Section, without the placeholder resources, Nevada Power is non-compliant with the RPS in 2029 in this case and Sierra is non-compliant in 2033.

Key findings of the combination cases analysis:

- All of the combination cases fully address the replacement of Valmy capacity and the voltage support and available around-the-clock generation needed in the Carlin Trend load pocket for a complete solution at Valmy. All except one of the cases achieve this through repowering of the Valmy units on natural gas, allowing coal combustion to be retired at the end of 2025.
- All combination cases add a renewable resource for RPS contribution as well as capacity.
- All cases that add 2 CTs have lower PWRR than comparable cases without them due, in part, to the low operating cost of firm dispatchable resources to meet – but not exceed – the energy needs of the Companies. These cases also have lower contributions to the renewable credits needed and tend to have higher GHG emissions compared to other combination cases.
- Of the combination cases, *Repower Valmy + SS + BESS* and *Repower Valmy + SS* have the lowest capital cost and add moderate amounts of capacity. For this reason, these two cases were chosen to move forward into the alternative plan analysis.
- The *Repower + SS + HP + IP* case has the highest contribution to RPS and also has the highest PWRR. The higher overall cost of this case indicates the size and commercial operation dates of these projects may not be ideal for the Companies.
- *Repower Valmy + 2 CTs + SS + BESS*, while least cost of all the combination cases, has the second highest capital cost, adding projects that contribute more capacity than any other

combination case. As the least cost of the combination cases, this case was chosen to move forward into the alternative plan analysis.

- *Repower Valmy + 2 CTs + SS* has the second lowest PWRR but the third highest capital cost, again adding large amounts of capacity. Of the combination cases that include both a repowered Valmy and the 2 CTs, adding substantial fossil capacity, the Companies progressed only the least cost case forward into the alternative plan analysis. Additional fossil capacity may be revisited in northern Nevada pending future forecasts of load growth.
- *2 CTs + BESS + SS* presents an alternate Valmy solution than the one chosen in the Valmy LSAP analysis. This case was chosen to move forward into the alternative plan analysis to address the requirement in Directive 4 in the Commission's June 12, 2023, Order in the Fourth Amendment for comprehensive analysis and comparisons of the financial and economic impacts of each potential complete solution at the Valmy coal plant.[62] This case presents a different solution from the Valmy LSAP analysis than the one chosen by the Companies. This case requires continued coal-fired operation of the Valmy units past the expected 2025 retirement date until the new CTs are in service in 2027, with a must-run of a Valmy unit until Greenlink West is in-service.
- The presence of the Valmy BESS tends to decrease the amount of solar overgeneration in a given case.

Tracy 4/5 LSAP. As described in the Generation Section, the Companies investigated the value of continuing the operation of the Tracy 4/5 plant beyond its current retirement date of December 2031. For this analysis, the plant was assumed to retire at the end of 2049. This analysis was conducted after the Valmy LSAP so that each case would fully address the voltage support and available around-the-clock generation needs of the Carlin Trend load pocket.

The L&R tables for the Tracy 4/5 LSAP analysis are provided in Technical Appendix ECON-5. The redacted cost summaries and load balances from the production cost model runs are included in Technical Appendix ECON-4. The CER analysis for each case is part of Technical Appendices ECON-6 and ECON-7.

The PWRR results of the Tracy 4/5 LSAP analysis are shown in Figure EA-12 below.

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[62] Docket No. 22-11032, June 12, 2023, Order, Directive 4 states: In a future resource plan amendment or the 2024 integrated resource plan, whichever comes first, NV Energy must provide the following related to the retirement of the coal-fired Valmy generating units:

a. A complete solution for the retirement of the Valmy coal plant;
b. Comprehensive analysis and comparisons of the financial and economic impacts of each potential solution; and,
c. Updated information on the federal and state limitations on continued operations of Valmy and associated costs.

FIGURE EA-12
RESULTS OF TRACY 4/5 LSAP SCREENING

	20 Year PWRR 2024-2043 (million $)	28 Year PWRR 2024-2051 (million $)	20 Year PWRR Change vs Least Cost Case (million $)	28 Year PWRR Change vs Least Cost Case (million $)
Base	$ 22,031	$ 28,458	$ 6	$ 18
Tracy 4_5	$ 22,025	$ 28,440	$ -	$ -

Key findings of the Tracy 4/5 LSAP analysis:

- The continued operation of Tracy 4/5 provides a portion of the capacity needed by the Companies. Although the overall savings for continuing the operation of the unit are rather low, continued operation decreases the Companies' reliance on uncertain market purchases.

The Tracy 4/5 LSAP indicates that it is cost effective to continue operation of Tracy 4/5 until 2049. More discussion of the Tracy 4/5 LSAP analysis can be found in the Generation Section.

<u>Alternative Plans.</u>

Informed by the analyses of the combination cases and Tracy 4/5 LSAP, a diverse set of alternative plans were created. Each plan includes the continued operation of Tracy 4/5. The alternative plans are described below.

Repower Valmy + 2 CTs + SS + BESS + T45. ("Repower Maximum Plan") This case combines the repower of the Valmy units, the 2 CTs at Valmy, Sierra Solar PV/BESS, the Valmy BESS with the continued operation of Tracy 4/5. Repower Valmy, Sierra Solar BESS and Valmy BESS all have expected in-service dates in 2026. Sierra Solar PV and Valmy CTs have expected in-service dates in 2027.

Repower Valmy + SS + BESS + T45. ("Repower Moderate Plan") This case combines the repower of the Valmy units, Sierra Solar PV/BESS, the Valmy BESS, and the continued operation of Tracy 4/5. Repower Valmy, Sierra Solar BESS and Valmy BESS all have expected in-service dates in 2026. Sierra Solar PV has an expected in-service date in 2027.

Repower Valmy + SS + T45. ("Repower Minimum Plan") This case combines the repower of the Valmy units, the Sierra Solar PV/BESS, and the continued operation of Tracy 4/5. Repower Valmy and Sierra Solar BESS both have expected in-service dates in 2026. Sierra Solar PV has an expected in-service date in 2027.

Valmy 2 CTs + BESS + SS + T45. ("No Repower Plan") This case combines 2 CTs at Valmy, Sierra Solar PV/BESS, the Valmy BESS, and the continued operation of Tracy 4/5. The Valmy BESS and the Sierra Solar BESS all have expected in-service dates in 2026. Sierra Solar PV and the two CTs have an expected in-service date in 2027. As previously discussed, this case presents an alternate Valmy solution than the one chosen in the Valmy LSAP analysis. This case was chosen to move forward into the alternative plan analysis to address the requirement in Directive 4 in the Commission's June 12, 2023, Order in the Fourth Amendment. This case requires continued coal-fired operation of the Valmy units past the expected 2025 retirement date until the new CTs are in service in 2027. Risks surrounding continued combustion of coal at Valmy past 2025 are discussed in the Generation Section.

These plans each provide a complete solution for the retirement of coal combustion at Valmy while addressing the required transmission support at this location. All plans address the need for RPS-contributing projects. In addition, all plans provide capacity by replacing placeholder resources with proposed projects which reduce the Companies' open position, addressing the loss of approved resources and continued uncertain availability of market capacity while simultaneously advancing resource sufficiency as required for participation in WRAP. All plans meet the PRM and RPS requirements and target the Companies' proportionate contribution to the state's 2050 clean energy goal.

Figures EA-13 and EA-14 present the detailed buildouts for the alternative plans. Adjustments to the Base Case placeholder resources are highlighted.

FIGURE EA-13
BUILDOUTS FOR
REPOWER MODERATE AND REPOWER MINIMUM PLANS

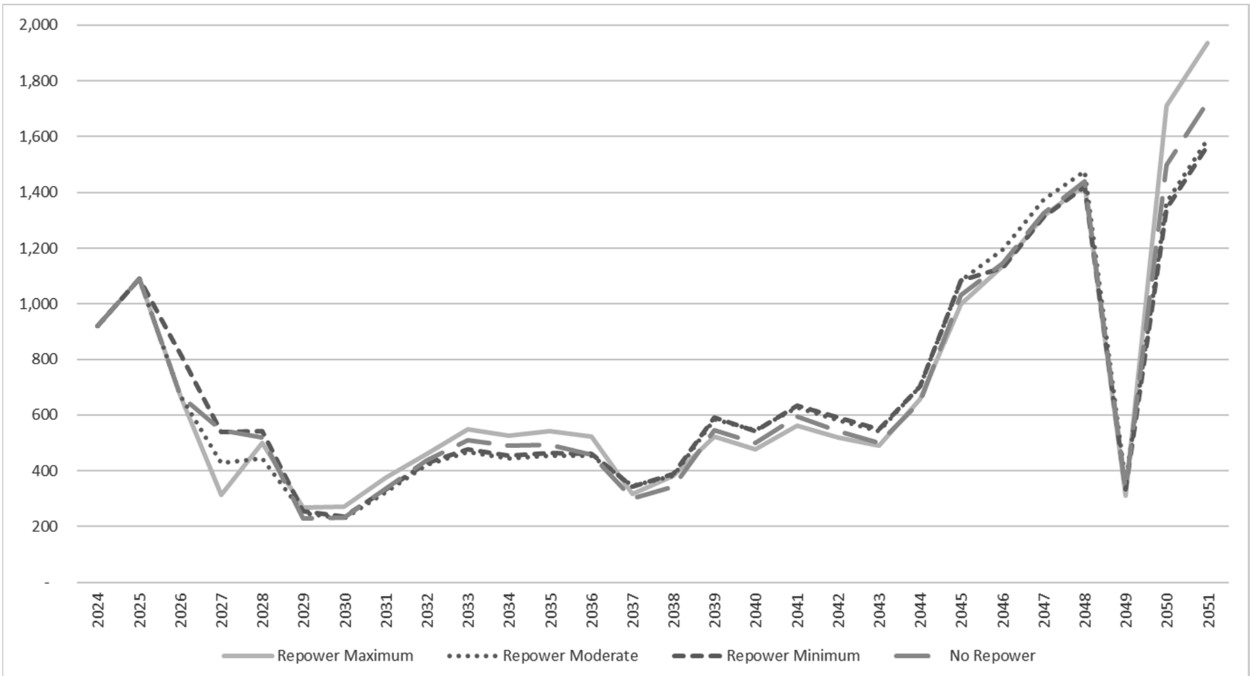
	Repower Moderate		Repower Minimum	
	Sierra	Nevada Power	Sierra	Nevada Power
2026	261 MW Repower Valmy_26 100 MW North BESS - SPPC_26 160 MW Sierra Solar BESS - paired - SPPC_26	100 MW North BESS - NPC_26 240 MW Sierra Solar BESS - paired - NPC_26	261 MW Repower Valmy_26 160 MW Sierra Solar BESS - paired - SPPC_26	240 MW Sierra Solar BESS - paired - NPC_26
2027	150 MW PV - paired_27 250 MW BESS - paired_27 160 MW Sierra Solar PV - paired - SPPC_27	300 MW PV - paired_27 190 MW BESS - paired_27 240 MW Sierra Solar PV - paired - NPC_27	250 MW PV - paired_27 300 MW BESS - paired_27 160 MW Sierra Solar PV - paired - SPPC_27	300 MW PV - paired_27 150 MW BESS - paired_27 240 MW Sierra Solar PV - paired - NPC_27
2028		230 MW PV - paired_28 270 MW BESS - paired_28		230 MW PV - paired_28 270 MW BESS - paired_28
2029	200 MW BESS - alone - SPPC_29	230 MW PV - paired - NPC_29 100 MW BESS - paired - NPC_29 200 MW BESS - alone - NPC_29	230 MW BESS - alone - SPPC_29	230 MW PV - paired - NPC_29 150 MW BESS - paired - NPC_29 280 MW BESS - alone - NPC_29
2030	440 MW PV - alone - SPPC_30	1030 MW PV - alone - NPC_30	440 MW PV - alone - SPPC_30	1030 MW PV - alone - NPC_30
2031				
2032	104 MW Tracy 4_5 2049 Extension_32	110 MW PV - alone_32	104 MW Tracy 4_5 2049 Extension_32	110 MW PV - alone_32
2033	210 MW PV - alone - SPPC_33	840 MW PV - alone - NPC_33 100 MW WIND - NV/AZ_33	210 MW PV - alone - SPPC_33	840 MW PV - alone - NPC_33 100 MW WIND - NV/AZ_33
2034	300 MW WIND - NV/AZ - SPPC_34	300 MW WIND - NV/AZ - NPC_34	300 MW WIND - NV/AZ - SPPC_34	300 MW WIND - NV/AZ - NPC_34
2035		130 MW PV - alone_35 230 MW WIND - NV/AZ_35		130 MW PV - alone_35 230 MW WIND - NV/AZ_35
2036	100 MW PV - alone - SPPC_36	380 MW PV - alone - NPC_36 280 MW BESS - alone_36	100 MW PV - alone - SPPC_36	380 MW PV - alone - NPC_36 280 MW BESS - alone_36
2037	210 MW BESS - alone - SPPC_37	400 MW PV - alone_37 260 MW BESS - alone - NPC_37	240 MW BESS - alone - SPPC_37	400 MW PV - alone_37 240 MW BESS - alone - NPC_37
2038	400 MW PV - alone - SPPC_38	400 MW PV - alone - NPC_38 100 MW WIND - NV/AZ_38 140 MW BESS - alone_38	400 MW PV - alone - SPPC_38	400 MW PV - alone - NPC_38 100 MW WIND - NV/AZ_38 140 MW BESS - alone_38
2039	280 MW PV - alone - SPPC_39 180 MW BESS - alone - SPPC_39	280 MW PV - alone - NPC_39 180 MW BESS - alone - NPC_39	280 MW PV - alone - SPPC_39 180 MW BESS - alone - SPPC_39	280 MW PV - alone - NPC_39 180 MW BESS - alone - NPC_39
2040		400 MW PV - alone_40 350 MW BESS - alone_40		400 MW PV - alone_40 350 MW BESS - alone_40
2041		290 MW PV - alone_41		290 MW PV - alone_41
2042	480 MW PV - alone_42	900 MW BESS - alone_42	480 MW PV - alone_42	900 MW BESS - alone_42
2043	580 MW BESS - alone_43	850 MW PV - alone_43	580 MW BESS - alone_43	850 MW PV - alone_43
2044	180 MW PV - alone - SPPC_44	720 MW PV - alone - NPC_44 350 MW BESS - alone_44	180 MW PV - alone - SPPC_44	720 MW PV - alone - NPC_44 350 MW BESS - alone_44
2045	300 MW WIND - ID_45	230 MW PV - alone_45 350 MW BESS - alone_45	300 MW WIND - ID_45	230 MW PV - alone_45 350 MW BESS - alone_45
2046		800 MW PV - alone_46		800 MW PV - alone_46
2047		900 MW PV - alone_47 550 MW BESS - alone_47		900 MW PV - alone_47 550 MW BESS - alone_47
2048		1050 MW PV - alone_48		1050 MW PV - alone_48
2049	900 MW Firm_dispatchable_NN_49	1150 MW PV - paired_49 1600 MW BESS - paired_49	900 MW Firm_dispatchable_NN_49	1150 MW PV - paired_49 1600 MW BESS - paired_49
2050	450 MW Firm_dispatchable_NN - SPPC_50 450 MW PV - alone_50	450 MW Firm_dispatchable_SN - NPC_50 2250 MW Firm_dispatchable_SN - NPC_50 3000 MW PV - paired_50 3000 MW BESS - paired_50	450 MW Firm_dispatchable_NN - SPPC_50 450 MW PV - alone_50	450 MW Firm_dispatchable_SN - NPC_50 2250 MW Firm_dispatchable_SN - NPC_50 3000 MW PV - paired_50 3000 MW BESS - paired_50

FIGURE EA-14
BUILDOUTS FOR
REPOWER MAXIMUM AND NO REPOWER PLANS

	Repower Maximum		No Repower	
	Sierra	Nevada Power	Sierra	Nevada Power
2026	261 MW Repower Valmy_26		0 MW Repower Valmy_26	
			261 MW Valmy on coal till end of 26	
	100 MW North BESS - SPPC_26	100 MW North BESS - NPC_26	100 MW North BESS - SPPC_26	100 MW North BESS - NPC_26
	160 MW Sierra Solar BESS - paired - SPPC_26	240 MW Sierra Solar BESS - paired - NPC_26	160 MW Sierra Solar BESS - paired - SPPC_26	240 MW Sierra Solar BESS - paired - NPC_26
2027	0 MW PV - paired_27	300 MW PV - paired_27	350 MW PV - paired_27	300 MW PV - paired_27
	0 MW BESS - paired_27	0 MW BESS - paired_27	0 MW BESS - paired_27	0 MW BESS - paired_27
	160 MW Sierra Solar PV - paired - SPPC_27	240 MW Sierra Solar PV - paired - NPC_27	160 MW Sierra Solar PV - paired - SPPC_27	240 MW Sierra Solar PV - paired - NPC_27
	220 MW North CT_27	220 MW North CT_27	220 MW North CT_27	220 MW North CT_27
2028		230 MW PV - paired_28		230 MW PV - paired_28
		0 MW BESS - paired_28		270 MW BESS - paired_28
2029		0 MW PV - paired - NPC_29		230 MW PV - paired - NPC_29
		0 MW BESS - paired - NPC_29		150 MW BESS - paired - NPC_29
	150 MW BESS - alone - SPPC_29	350 MW BESS - alone - NPC_29	200 MW BESS - alone - SPPC_29	250 MW BESS - alone - NPC_29
2030	370 MW PV - alone - SPPC_30	1100 MW PV - alone - NPC_30	290 MW PV - alone - SPPC_30	1180 MW PV - alone - NPC_30
2031				
2032	104 MW Tracy 4_5 2049 Extension_32	300 MW PV - alone_32	104 MW Tracy 4_5 2049 Extension_32	110 MW PV - alone_32
2033	210 MW PV - alone - SPPC_33	840 MW PV - alone - NPC_33	210 MW PV - alone - SPPC_33	840 MW PV - alone - NPC_33
		100 MW WIND - NV/AZ_33		100 MW WIND - NV/AZ_33
2034	300 MW WIND - NV/AZ - SPPC_34	300 MW WIND - NV/AZ - NPC_34	300 MW WIND - NV/AZ - SPPC_34	300 MW WIND - NV/AZ - NPC_34
2035		130 MW PV - alone_35		130 MW PV - alone_35
		230 MW WIND - NV/AZ_35		230 MW WIND - NV/AZ_35
2036	100 MW PV - alone - SPPC_36	380 MW PV - alone - NPC_36	100 MW PV - alone - SPPC_36	380 MW PV - alone - NPC_36
		200 MW BESS - alone_36		250 MW BESS - alone_36
2037	200 MW BESS - alone - SPPC_37	400 MW PV - alone_37	210 MW BESS - alone - SPPC_37	400 MW PV - alone_37
		200 MW BESS - alone - NPC_37		260 MW BESS - alone - NPC_37
2038	400 MW PV - alone - SPPC_38	400 MW PV - alone - NPC_38	400 MW PV - alone - SPPC_38	400 MW PV - alone - NPC_38
		100 MW WIND - NV/AZ_38		100 MW WIND - NV/AZ_38
		100 MW BESS - alone_38		140 MW BESS - alone_38
2039	280 MW PV - alone - SPPC_39	280 MW PV - alone - NPC_39	280 MW PV - alone - SPPC_39	280 MW PV - alone - NPC_39
	180 MW BESS - alone - SPPC_39	180 MW BESS - alone - NPC_39	180 MW BESS - alone - SPPC_39	180 MW BESS - alone - NPC_39
2040		400 MW PV - alone_40		400 MW PV - alone_40
		350 MW BESS - alone_40		350 MW BESS - alone_40
2041		290 MW PV - alone_41		290 MW PV - alone_41
2042	480 MW PV - alone_42	900 MW BESS - alone_42	480 MW PV - alone_42	900 MW BESS - alone_42
2043	450 MW BESS - alone_43	850 MW PV - alone_43	500 MW BESS - alone_43	850 MW PV - alone_43
2044	180 MW PV - alone - SPPC_44	720 MW PV - alone - NPC_44	180 MW PV - alone - SPPC_44	720 MW PV - alone - NPC_44
		250 MW BESS - alone_44		350 MW BESS - alone_44
2045	300 MW WIND - ID_45	230 MW PV - alone_45	300 MW WIND - ID_45	230 MW PV - alone_45
		350 MW BESS - alone_45		350 MW BESS - alone_45
2046		800 MW PV - alone_46		800 MW PV - alone_46
2047		900 MW PV - alone_47		900 MW PV - alone_47
		550 MW BESS - alone_47		550 MW BESS - alone_47
2048		1050 MW PV - alone_48		1050 MW PV - alone_48
2049	900 MW Firm_dispatchable_NN_49	1150 MW PV - paired_49	900 MW Firm_dispatchable_NN_49	1150 MW PV - paired_49
		1600 MW BESS - paired_49		1600 MW BESS - paired_49
2050	450 MW Firm_dispatchable_NN - SPPC_50	450 MW Firm_dispatchable_SN - NPC_50	450 MW Firm_dispatchable_NN - SPPC_50	450 MW Firm_dispatchable_SN - NPC_50
	450 MW PV - alone_50	2250 MW Firm_dispatchable_SN - NPC_50	450 MW PV - alone_50	2250 MW Firm_dispatchable_SN - NPC_50
		3000 MW PV - paired_50		3000 MW PV - paired_50
		3000 MW BESS - paired_50		3000 MW BESS - paired_50

Figure EA-15 presents the open positions associated with the alternative plans. The placeholders in each plan have been adjusted to maintain a similar open position in each case for similar reliability.

FIGURE EA-15
OPEN POSITION FOR ALTERNATIVE PLANS



As mentioned in discussion of the combination cases, there is a significant change in open position in 2049 in all cases. This anomaly is caused by the method the Companies used in adding and removing capacity from the L&R tables. As described in more detail earlier, the amount of available capacity in 2049 is overstated because of the timing of placeholders and capacity accounting used in the L&R table, causing a drop in open position. The sharp drop in open position will likely not occur.

The placeholders assumed in each of these cases are provided in the respective L&R tables which can be found in Technical Appendix ECON-5. In addition, Figures EA-16 and EA-17 are provided to further illustrate the placeholder differences between the cases in the early years, where they are most notable, and the later years, as a bookend.

FIGURE EA-16
PLACEHOLDER RESOURCES - ALTERNATIVE PLANS, 2027-2032

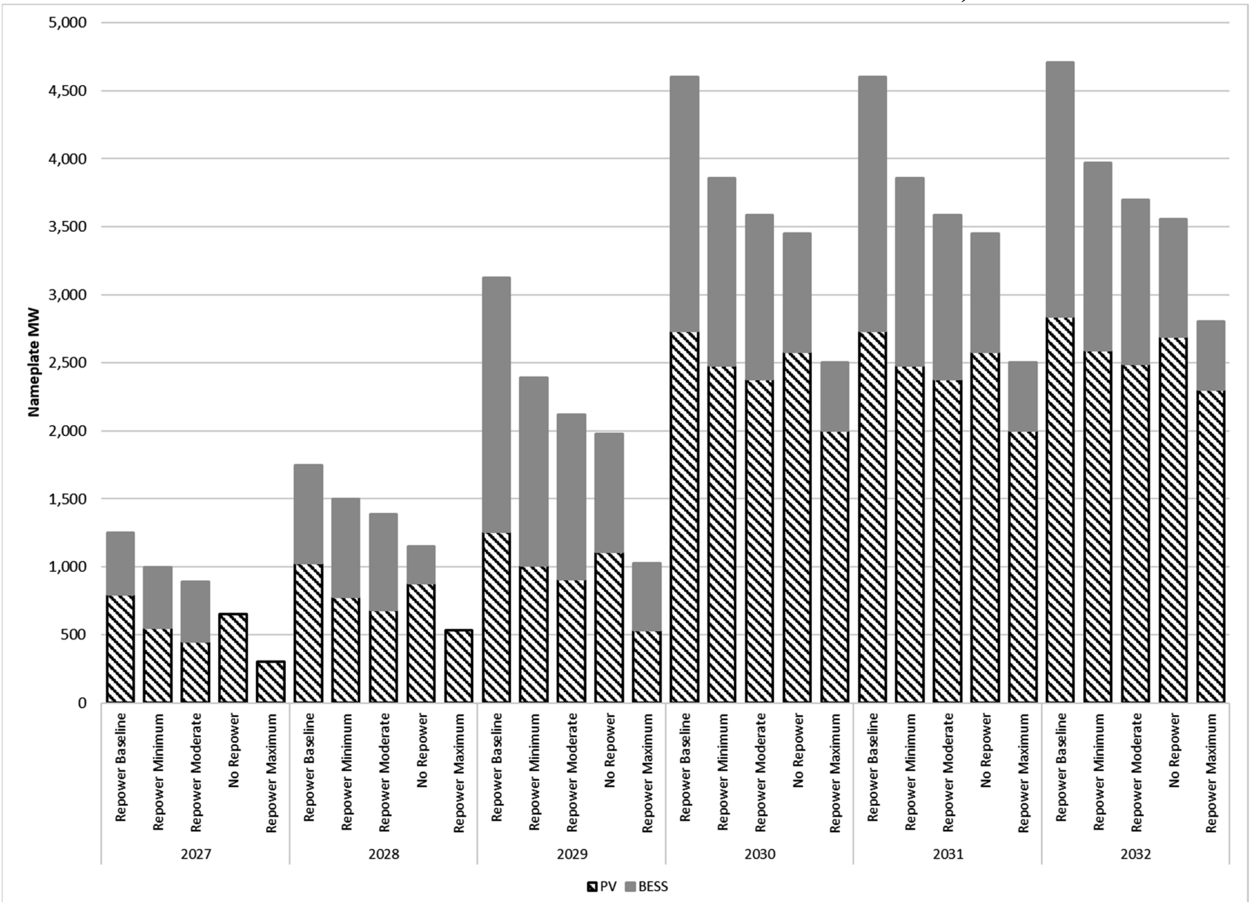
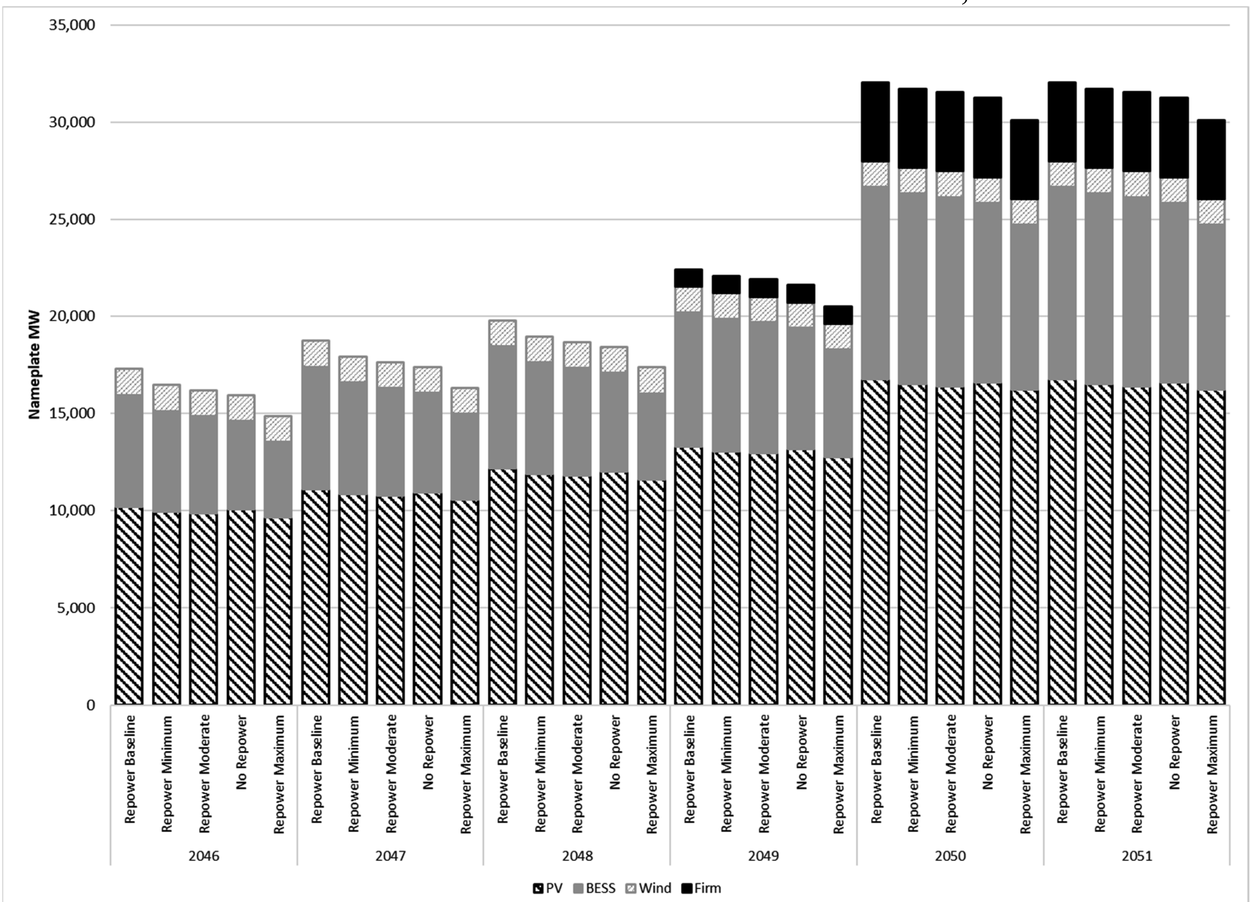


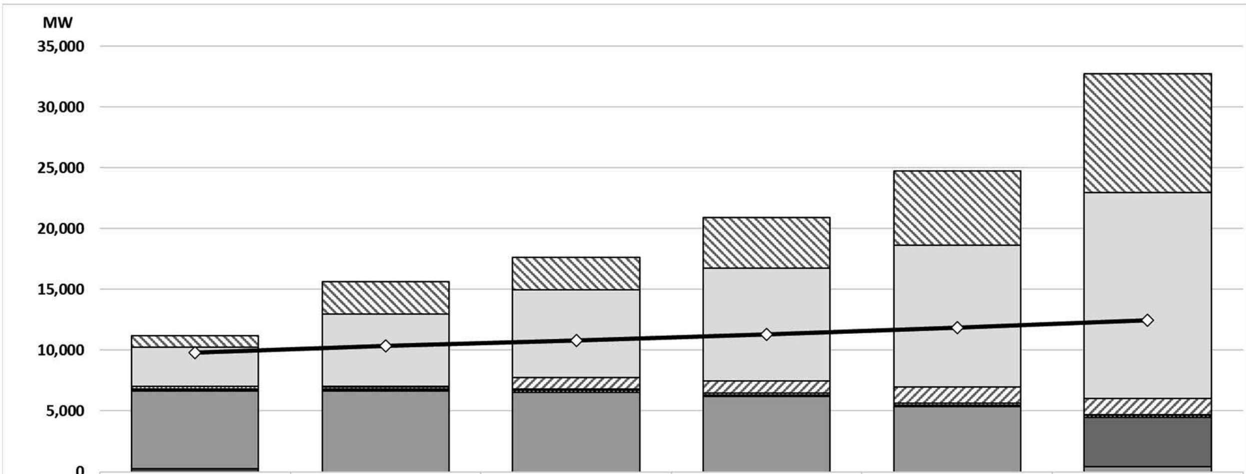
FIGURE EA-17
PLACEHOLDER RESOURCES - ALTERNATIVE PLANS, 2046-2051



Discussion of Alternative Plans:

Repower Minimum Plan. This plan adds the resources presented in Figure EA-13, adding the least project capacity of all alternative plans. Figure EA-18 shows the installed capacity for this plan in five-year intervals from 2025 to 2050. The Planning Reserve Margin Requirement ("PRMR") line indicates the effective capacity required at the time of the system peak, which is the Required Resources row on the L&R table plus 90 MW of OATT Reserves. The installed capacity of renewable units reflects the maximum output of the generator, not the effective capacity or ELCC.

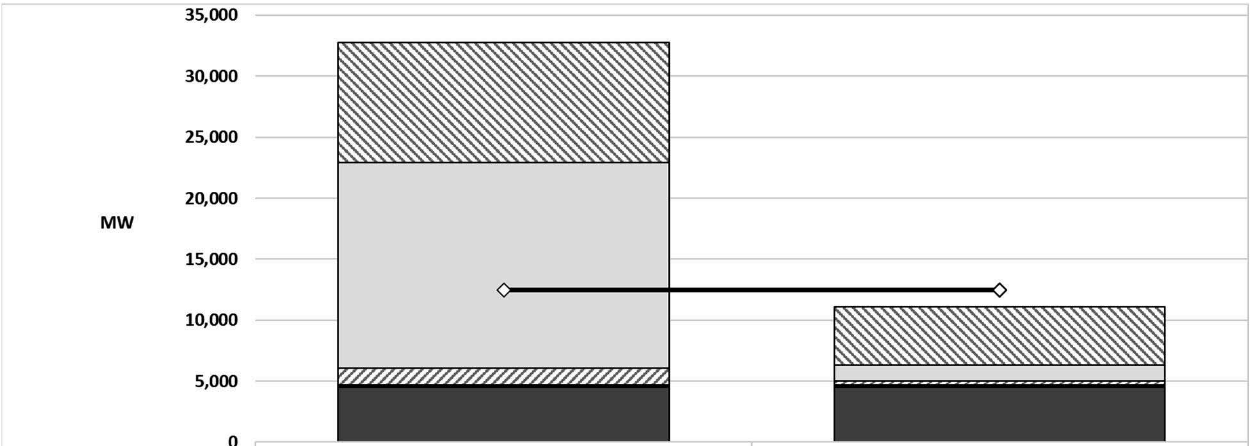
FIGURE EA-18
INSTALLED CAPACITY FOR REPOWER MINIMUM



	2025	2030	2035	2040	2045	2050
BESS	978	2,698	2,673	4,150	6,110	9,810
Solar	3,205	5,953	7,225	9,286	11,701	16,910
Wind	20	20	930	1,030	1,330	1,330
Geo	197	189	124	119	119	94
Hydro	129	119	119	119	119	119
Other	31	26	5	5	-	-
Firm	-	-	-	-	-	4,050
Gas	6,386	6,647	6,543	6,201	5,378	444
Coal	261	-	-	-	-	-
PRMR	9,818	10,357	10,805	11,305	11,880	12,450

To further illustrate the difference between installed and effective capacity (at time of peak) in 2050, the Companies present Figure EA-19. The figure demonstrates the low effective capacity of renewable resources at high penetrations in comparison to the strong contribution of firm dispatchable resources to resource adequacy. Note, the open position is the difference between the PRMR line and the total firm capacity.

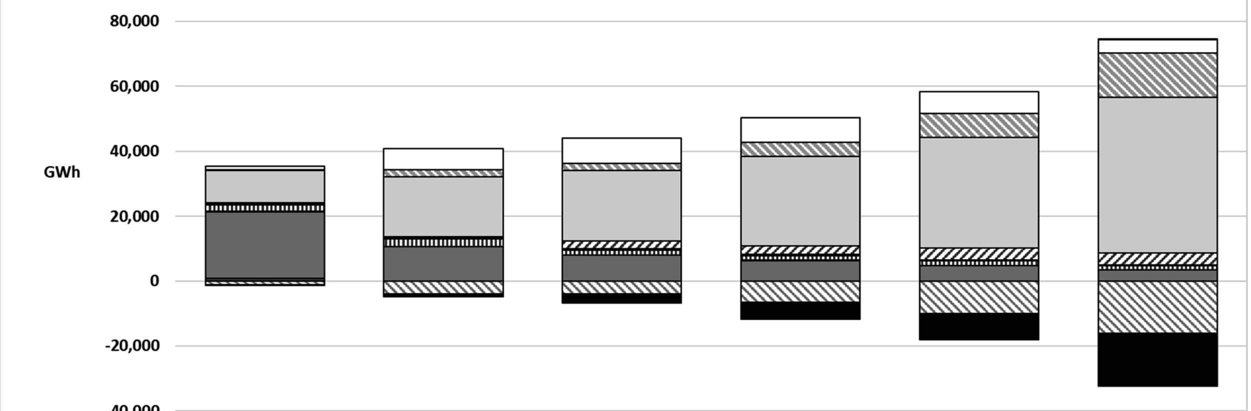
FIGURE EA-19
2050 INSTALLED CAPACITY VERSUS FIRM CAPACITY
FOR REPOWER MINIMUM



	Installed Capacity	Firm Capacity (ELCC)
BESS	9,810	4,789
Solar	16,910	1,310
Wind	1,330	302
Geo	94	94
Hydro	119	119
Gas & Firm Dispatchable	4,494	4,494
PRMR	12,450	12,450

The energy production by resource type for this plan is shown in Figure EA-20. Note that, although the gas and firm dispatchable resource capacity stays relatively flat for the first 20 years of the study period, the corresponding energy output of these resources decreases dramatically over the same period as they continue to contribute significantly to resource adequacy while incurring diminishing pollutant emissions.

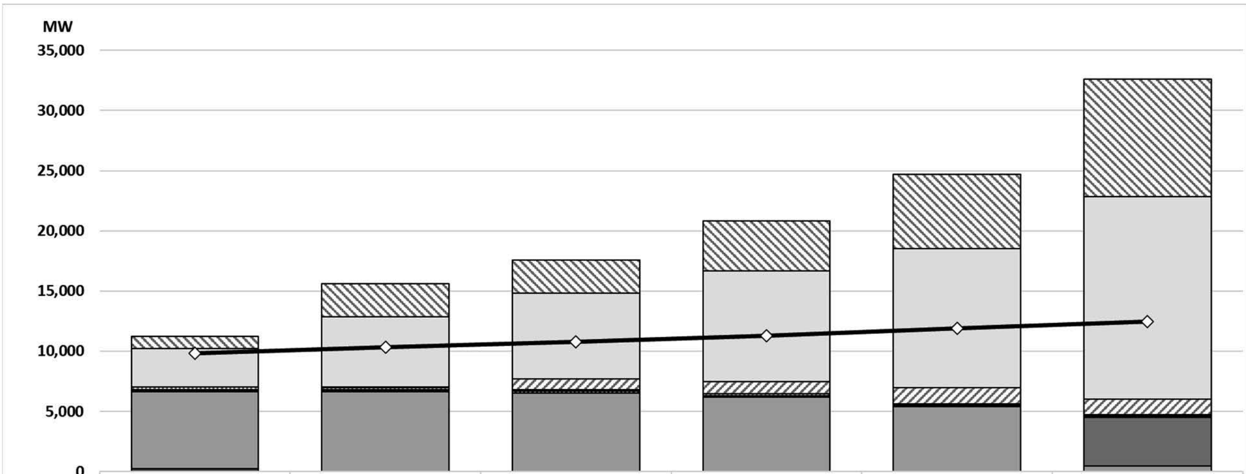
FIGURE EA-20
ENERGY PRODUCTION FOR REPOWER MINIMUM



	2025	2030	2035	2040	2045	2050
Emergency Energy	0	0	0	0	0	1
Market Energy	941	6,454	7,748	7,649	6,630	4,018
Battery Discharge	168	2,110	2,112	4,437	7,392	13,671
Solar	9,961	18,602	21,976	27,585	34,261	48,120
Wind	347	347	2,431	2,694	3,640	3,640
Hydro	334	293	278	274	260	220
Geo	2,057	2,399	1,559	1,483	1,479	1,262
Other	254	111	27	27	0	0
Gas & Firm	20,515	10,455	7,930	6,284	4,639	3,433
Coal	736	0	0	0	0	0
Excess Energy	-54	-771	-2,794	-5,209	-8,166	-16,287
Battery Charging	-1,112	-4,093	-4,039	-6,552	-9,970	-16,096

Repower Moderate Plan. This plan adds the resources presented in Figure EA-13. Figure EA-21 shows the installed capacity for this plan in five-year intervals from 2025 to 2050. The PRMR line indicates the effective capacity required at the time of the system peak, which is the Required Resources on the L&R table plus 90 MW of OATT Reserves.

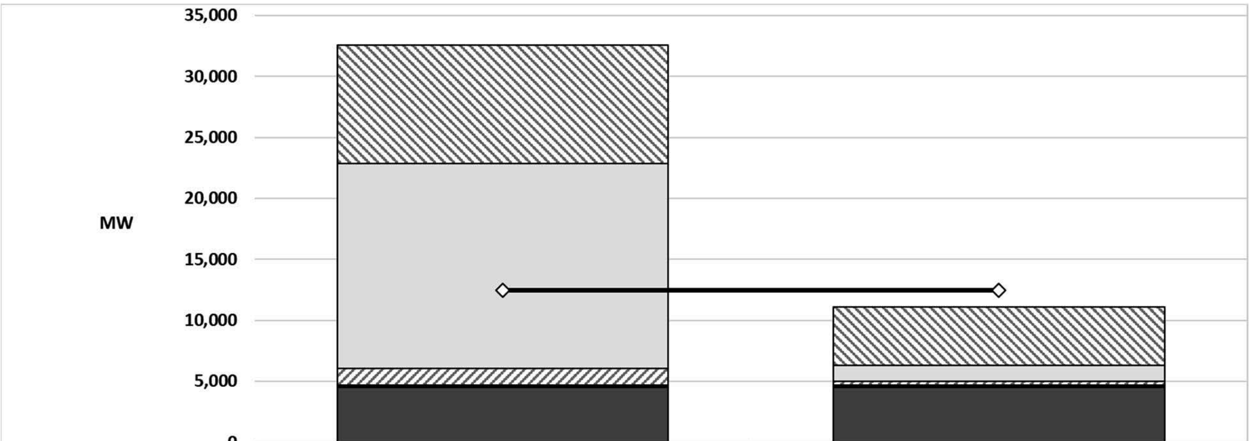
FIGURE EA-21
INSTALLED CAPACITY FOR REPOWER MODERATE



	2025	2030	2035	2040	2045	2050
BESS	978	2,728	2,703	4,170	6,130	9,740
Solar	3,205	5,853	7,125	9,186	11,601	16,810
Wind	20	20	930	1,030	1,330	1,330
Geo	197	189	124	119	119	94
Hydro	129	119	119	119	119	119
Other	31	26	5	5	-	-
Firm	-	-	-	-	-	4,050
Gas	6,386	6,647	6,543	6,201	5,378	444
Coal	261	-	-	-	-	-
PRMR	9,818	10,357	10,805	11,305	11,880	12,450

As presented for the Repower Minimum Plan, <u>Figure EA-22</u> shows a comparison of installed capacity to firm capacity, or ELCC, in 2050.

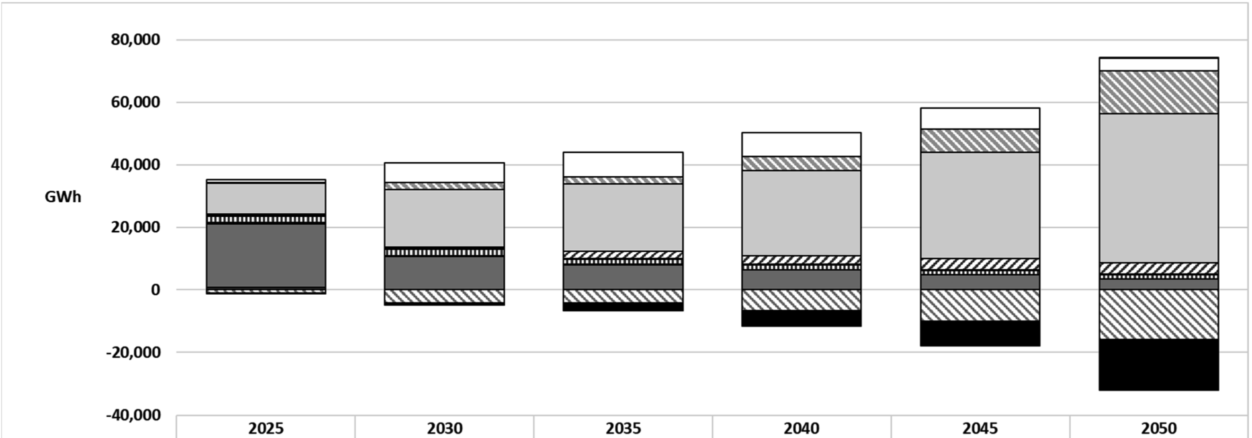
FIGURE EA-22
2050 INSTALLED CAPACITY VERSUS FIRM CAPACITY FOR REPOWER MODERATE



	Installed Capacity	Firm Capacity (ELCC)
BESS	9,740	4,768
Solar	16,810	1,307
Wind	1,330	302
Geo	94	94
Hydro	119	119
Gas & Firm Dispatchable	4,494	4,494
PRMR	12,450	12,450

The energy production by resource type for this plan is shown in Figure EA-23.

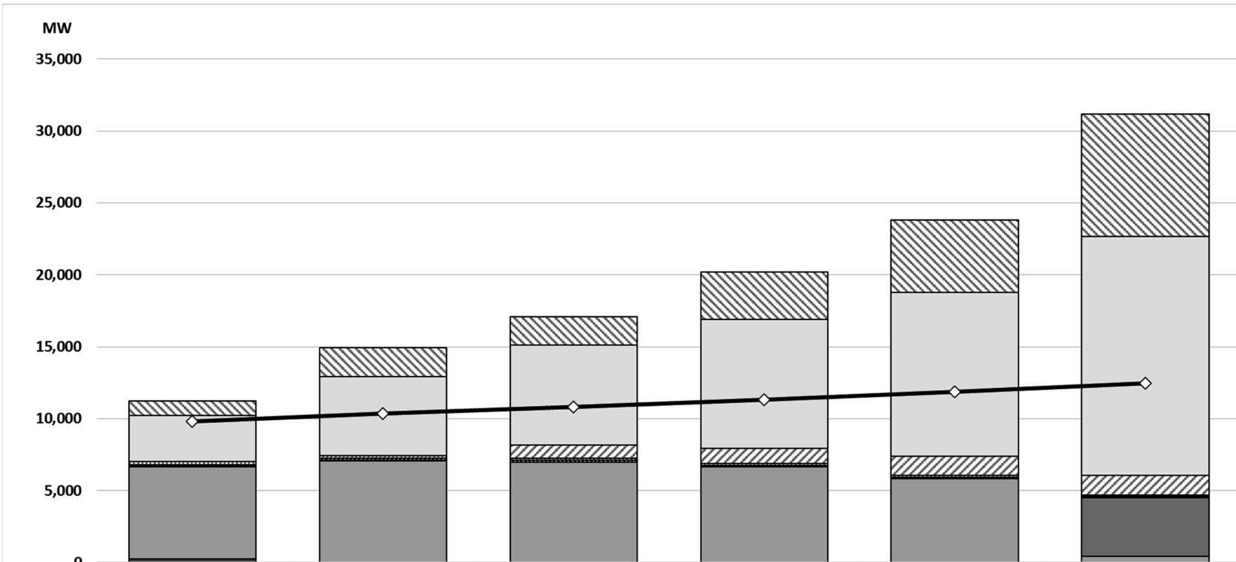
FIGURE EA-23
ENERGY PRODUCTION FOR REPOWER MODERATE



	2025	2030	2035	2040	2045	2050
Emergency Energy	0	0	0	0	0	1
Market Energy	941	6,421	7,752	7,676	6,653	4,078
Battery Discharge	168	2,179	2,198	4,526	7,452	13,551
Solar	9,961	18,314	21,688	27,297	33,974	47,834
Wind	347	347	2,431	2,694	3,640	3,640
Hydro	334	293	278	274	262	222
Geo	2,057	2,399	1,559	1,483	1,479	1,262
Other	254	111	27	27	0	0
Gas & Firm	20,515	10,649	8,025	6,311	4,664	3,480
Coal	736	0	0	0	0	0
Excess Energy	-54	-640	-2,595	-4,962	-7,920	-16,132
Battery Charging	-1,112	-4,166	-4,137	-6,653	-10,039	-15,954

Repower Maximum Plan. This plan adds the resources presented in Figure EA-14, adding the most project capacity of all the alternative plans. Figure EA-24 shows the installed capacity for this plan in five-year intervals from 2025 to 2050. The PRMR line indicates the effective capacity required at the time of the system peak, which is the Required Resources on the L&R table plus 90 MW of OATT Reserves.

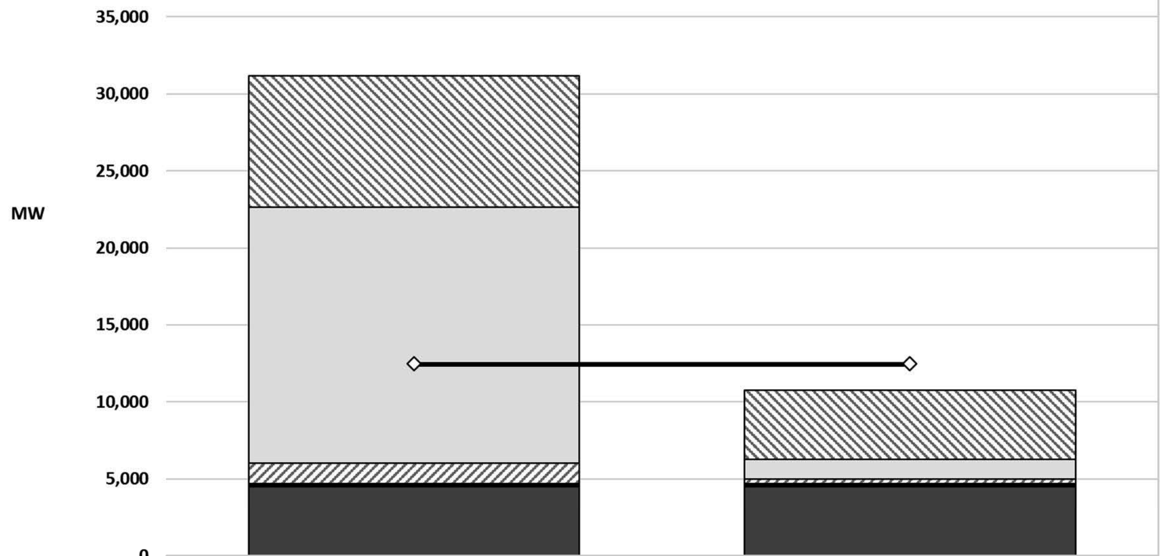
FIGURE EA-24
INSTALLED CAPACITY FOR REPOWER MAXIMUM



	2025	2030	2035	2040	2045	2050
BESS	978	2,018	1,993	3,270	5,000	8,510
Solar	3,205	5,473	6,935	8,996	11,411	16,620
Wind	20	20	930	1,030	1,330	1,330
Geo	197	189	124	119	119	94
Hydro	129	119	119	119	119	119
Other	31	26	5	5	-	-
Firm	-	-	-	-	-	4,050
Gas	6,386	7,087	6,983	6,641	5,818	444
Coal	261	-	-	-	-	-
PRMR	9,818	10,357	10,805	11,305	11,880	12,450

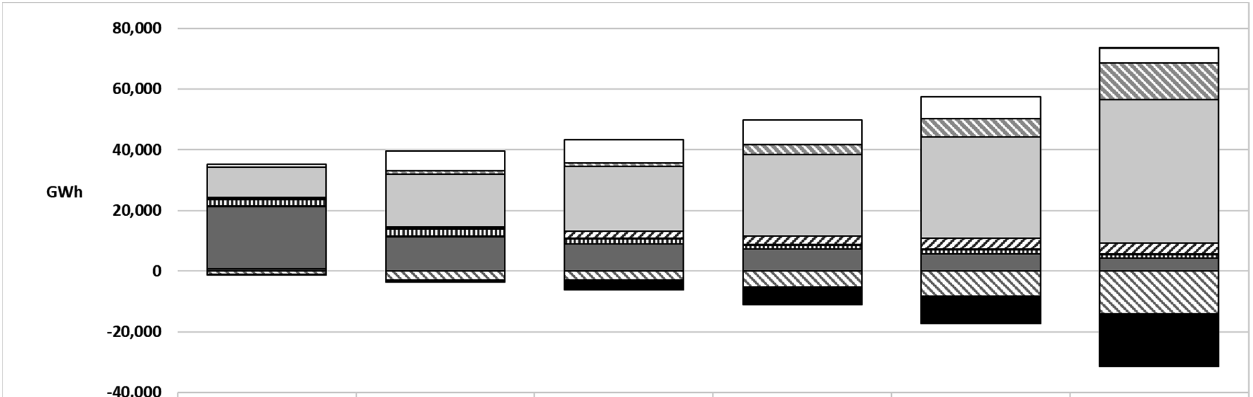
A comparison of the 2050 installed versus firm capacity for this plan can be seen in Figure EA-25.

FIGURE EA-25
2050 INSTALLED CAPACITY VERSUS FIRM CAPACITY FOR REPOWER MAXIMUM



	Installed Capacity	Firm Capacity (ELCC)
BESS	8,510	4,478
Solar	16,620	1,253
Wind	1,330	302
Geo	94	94
Hydro	119	119
Gas & Firm Dispatchable	4,494	4,494
PRMR	12,450	12,450

FIGURE EA-26
ENERGY PRODUCTION FOR REPOWER MAXIMUM

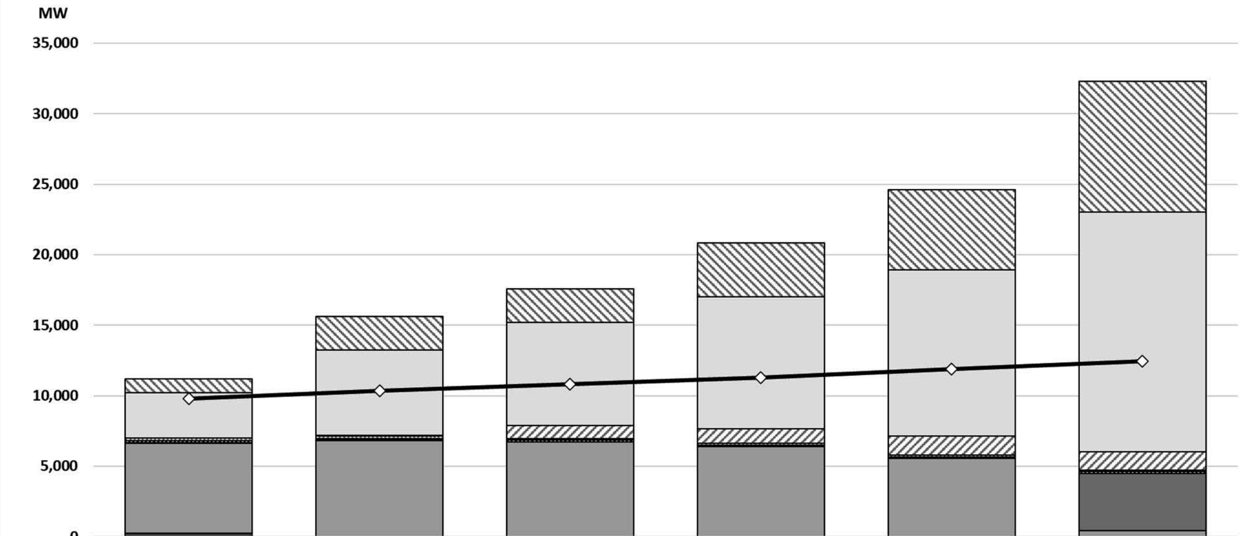


	2025	2030	2035	2040	2045	2050
Emergency Energy	0	0	0	0	0	1
Market Energy	941	6,520	7,665	7,976	7,223	4,926
Battery Discharge	168	1,225	1,234	3,305	5,924	11,900
Solar	9,961	17,242	21,160	26,767	33,459	47,306
Wind	347	347	2,431	2,694	3,640	3,640
Hydro	334	294	277	279	269	241
Geo	2,057	2,399	1,559	1,483	1,479	1,262
Other	254	111	27	27	0	0
Gas & Firm	20,515	11,504	9,022	7,175	5,508	4,152
Coal	736	0	0	0	0	0
Excess Energy	-54	-694	-3,147	-5,821	-9,081	-17,440
Battery Charging	-1,112	-3,042	-3,002	-5,213	-8,255	-14,006

No Repower Plan. This plan adds the resources presented in Figure EA-14. This plan addresses Directive 4 in the Commission's June 12, 2023, Order in the Fourth Amendment by providing a different complete Valmy solution than that presented in the other alternative plans. This plan requires continuation of the coal-fired Valmy units past the expected 2025 retirement date until the new CTs are in service in 2027, with a must-run of one Valmy unit until Greenlink West is in service. Risks surrounding continued combustion of coal at Valmy past 2025 are discussed in the Generation Section.

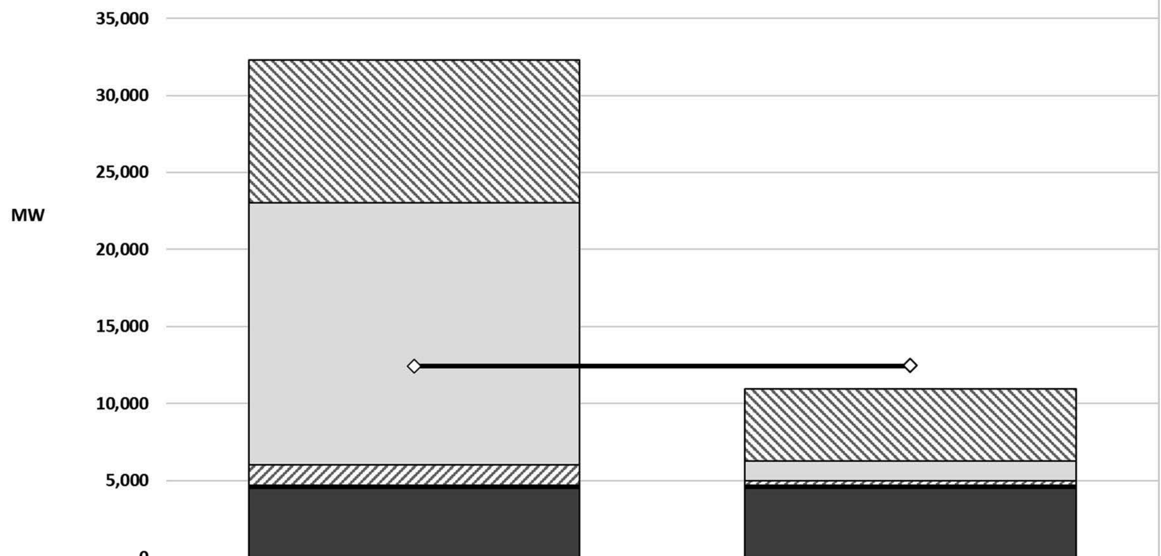
Figure EA-27 shows the installed capacity for this plan in five-year intervals from 2025 to 2050. The PRMR line indicates the effective capacity required at the time of the system peak, which is the Required Resources on the L&R table plus 90 MW of OATT Reserves.

FIGURE EA-27
INSTALLED CAPACITY FOR VALMY NO REPOWER



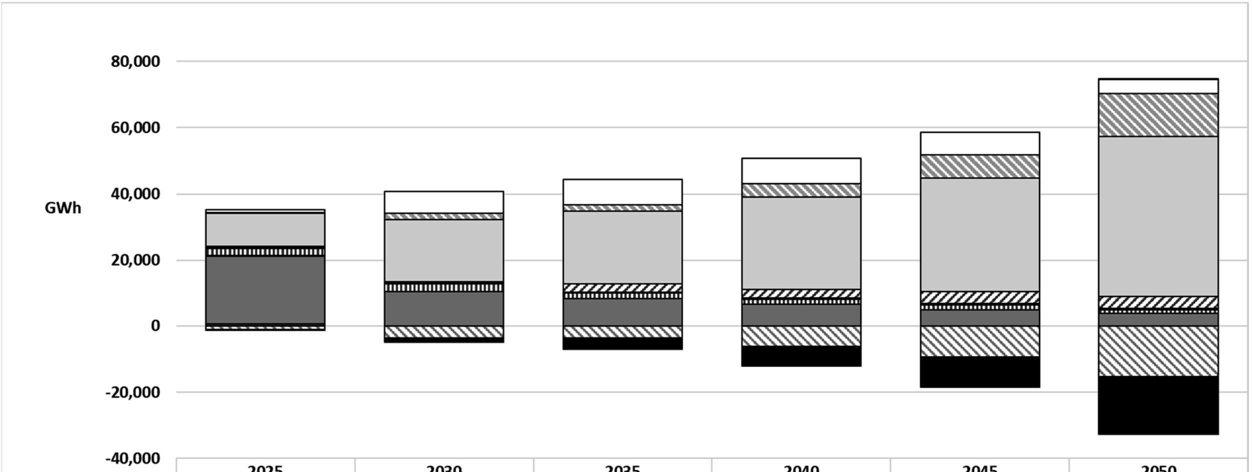
	2025	2030	2035	2040	2045	2050
BESS	978	2,388	2,363	3,800	5,680	9,240
Solar	3,205	6,053	7,325	9,386	11,801	17,010
Wind	20	20	930	1,030	1,330	1,330
Geo	197	189	124	119	119	94
Hydro	129	119	119	119	119	119
Other	31	26	5	5	-	-
Firm	-	-	-	-	-	4,050
Gas	6,386	6,826	6,722	6,380	5,557	444
Coal	261	-	-	-	-	-
PRMR	9,818	10,357	10,805	11,305	11,880	12,450

FIGURE EA-28
2050 INSTALLED CAPACITY VERSUS FIRM CAPACITY FOR NO REPOWER



	Installed Capacity	Firm Capacity (ELCC)
BESS	9,240	4,659
Solar	17,010	1,282
Wind	1,330	302
Geo	94	94
Hydro	119	119
Gas & Firm Dispatchable	4,494	4,494
PRMR	12,450	12,450

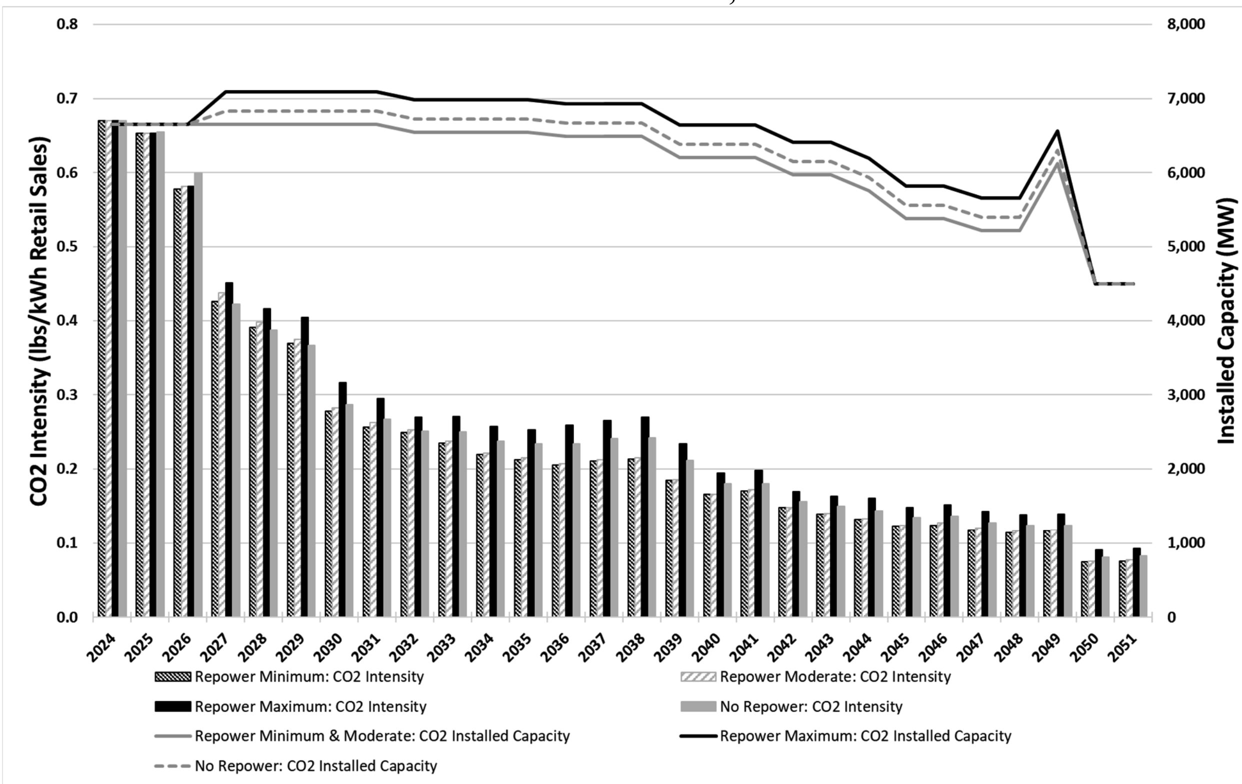
FIGURE EA-29
ENERGY PRODUCTION FOR NO REPOWER



	2025	2030	2035	2040	2045	2050
Emergency Energy	0	0	0	0	0	1
Market Energy	938	6,577	7,610	7,713	6,823	4,380
Battery Discharge	168	1,756	1,761	4,057	6,884	12,931
Solar	9,961	18,886	22,259	27,868	34,554	48,405
Wind	347	347	2,431	2,694	3,640	3,640
Hydro	334	294	279	276	265	231
Geo	2,057	2,399	1,559	1,483	1,479	1,262
Other	254	111	27	27	0	0
Gas & Firm	20,510	10,328	8,359	6,632	4,968	3,727
Coal	743	0	0	0	0	0
Excess Energy	-53	-1,120	-3,436	-5,976	-9,066	-17,371
Battery Charging	-1,112	-3,671	-3,622	-6,101	-9,382	-15,222

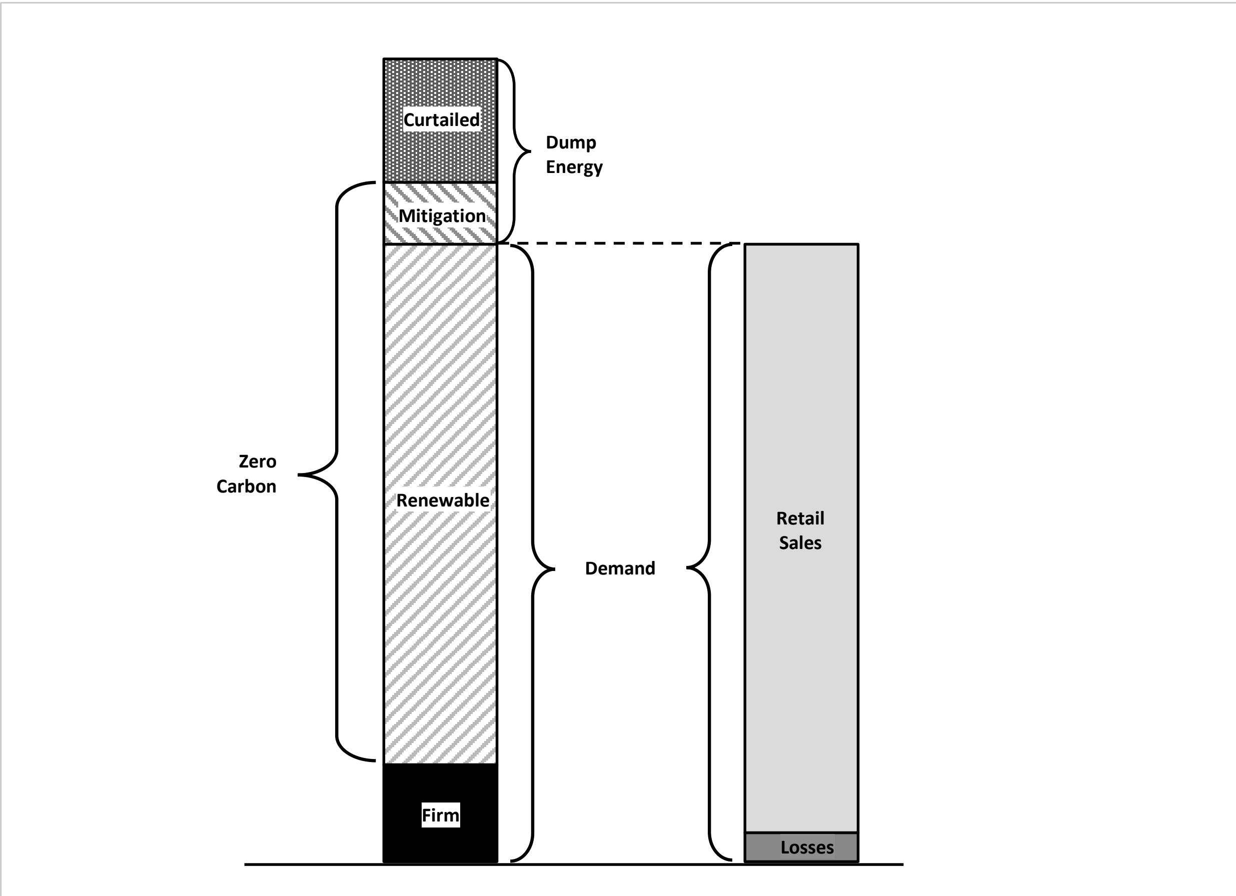
Carbon Emissions. A comparison of the carbon intensity of the alternative plans in pounds ("lbs") of carbon dioxide ("CO_2") per kWh of retail sales is depicted in Figure EA-30. Consistent with calculations in previous filings, the emissions used for this figure assumed no carbon value for market purchases. The bump in carbon intensity in 2049 corresponds with the open position anomaly evident in Figure EA-13. As described in more detail previously, the amount of available capacity in 2049 is overstated because of the timing of placeholders and capacity accounting used in the L&R table, causing a drop in open position. The sharp drop in open position and associated spike in carbon intensity will likely not occur.

FIGURE EA-30
JOINT SYSTEM CARBON INTENSITY, ALTERNATIVE PLANS



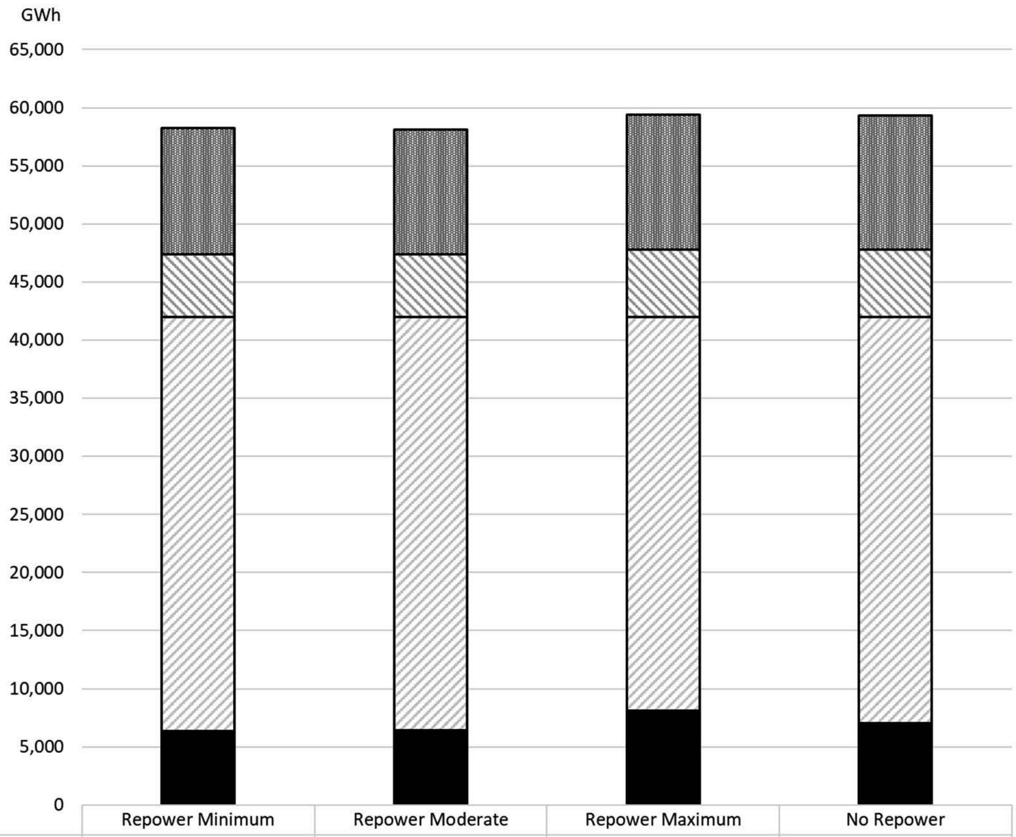
Calculation of Zero-Carbon Generation. The state's 2050 clean energy goal requires an amount of generation from zero-carbon dioxide emission resources that is equal to electricity sales in 2050. This analysis in this Fifth Amendment is performed in the same manner as in prior recent filings – considering only generation owned or under contract to the Companies. Figure EA-31 illustrates the calculation of zero-carbon generation. The PLEXOS analysis determines the generation to serve customer demand. Demand is the sum of retail sales plus system losses. Generation consists of energy produced by renewable and non-renewable resources and a portion of the overgeneration (or dump) energy. As indicated in previous filings, the Companies believe a portion of overgeneration will be mitigated. That is, a portion of over-generated energy may be used by the system through more optimal utilization of the batteries or through off-system sales. 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-31
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-32. A breakdown of the energy mix for these cases is provided in Technical Appendix ECON-4.

FIGURE EA- 32
CALCULATION OF 2050 GENERATION BY PLAN



	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
Curtailed	10,858	10,755	11,626	11,581
Mitigation	5,429	5,377	5,813	5,790
Renewables	35,635	35,528	33,902	34,957
Firm Dispatchable	6,347	6,454	8,080	7,025
Zero Carbon Generation (Renewables+Mitigation)	**41,064**	**40,906**	**39,715**	**40,747**
Retail Sales	**39,366**	**39,366**	**39,366**	**39,366**
Percent Zero Carbon Generation	**104%**	**104%**	**101%**	**104%**

F. Economic Analysis Results

The results of PWRR comparison for the alternative plans are presented in Figure EA-33. The base load, base fuel, mid-carbon price scenario shows the Repower Maximum Plan to be least cost, with the Repower Minimum Plan second, and the Repower Moderate Plan a close third. The No Repower Plan is higher cost than the other alternative plans.

FIGURE EA-33
PWRR RESULTS OF ALTERNATIVE PLANS

	20 Year PWRR 2024-2043 (million $)	28 Year PWRR 2024-2051 (million $)	20 Year PWRR Change vs Least Cost Case (million $)	28 Year PWRR Change vs Least Cost Case (million $)
Repower Maximum	$ 21,841	$ 28,101	$ -	$ -
Repower Moderate	$ 22,123	$ 28,541	$ 282	$ 440
Repower Minimum	$ 22,095	$ 28,534	$ 254	$ 434
No Repower	$ 22,210	$ 28,610	$ 369	$ 509

The Companies conducted several fuel/purchased power/carbon price and load scenarios to test the results given reasonable changes in the key assumptions used in the analysis. The results of the scenario analyses are presented in Figures EA-34 and EA-35. A discussion of key findings follows the figures.

<u>Scenario Analysis.</u> The alternative plans prepared for this analysis were tested using base, high, and low economic growth scenarios. These forecasts were presented in the Companies' Third Amendment. In addition, the cases will be tested using base, high, and low fuel and purchased power price forecasts. The mid-level carbon impact assumption has been tested with high and no carbon price sensitivities. Further details on these forecasts can be found in the Fuel and Purchased Power Price Forecast Section.

As described in subsection C, Updates to Key Modeling Assumptions, the Companies have chosen to use the high price coal forecast in the base and fuel price analyses. The mid-level coal price forecast was used for the low fuel price sensitivity.

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

FIGURE EA-34
20-YEAR PWRR FOR ALL PLANS AND SCENARIOS

20-year PWRR ($ millions) by Scenario							
	Base Load					HLBFMC	LLBFMC
	BLBFMC	BLBFNC	BLBFHC	BLHFMC	BLLFMC		
Repower Maximum	$ 21,841	$ 22,003	$ 21,624	$ 29,639	$ 17,651	$ 22,774	$ 20,707
Repower Moderate	$ 22,123	$ 22,274	$ 21,927	$ 29,517	$ 18,242	$ 23,057	$ 21,002
Repower Minimum	$ 22,095	$ 22,244	$ 21,900	$ 29,449	$ 18,230	$ 23,025	$ 20,967
No Repower	$ 22,210	$ 22,365	$ 22,005	$ 29,640	$ 18,202	$ 23,133	$ 21,094

20-year PWRR Differential ($ millions) by Scenario							
	Base Load					HLBFMC	LLBFMC
	BLBFMC	BLBFNC	BLBFHC	BLHFMC	BLLFMC		
Repower Maximum	$ -	$ -	$ -	$ 190	$ -	$ -	$ -
Repower Moderate	$ 282	$ 270	$ 303	$ 68	$ 592	$ 283	$ 295
Repower Minimum	$ 254	$ 240	$ 276	$ -	$ 579	$ 251	$ 260
No Repower	$ 369	$ 361	$ 381	$ 190	$ 552	$ 359	$ 388

20-year PWRR Ranking by Scenario							
	Base Load					HLBFMC	LLBFMC
	BLBFMC	BLBFNC	BLBFHC	BLHFMC	BLLFMC		
Repower Maximum	1	1	1	3	1	1	1
Repower Moderate	3	3	3	2	4	3	3
Repower Minimum	2	2	2	1	3	2	2
No Repower	4	4	4	4	2	4	4

FIGURE EA-35
STUDY PERIOD PWRR FOR ALL PLANS AND SCENARIOS

28-year PWRR ($ millions) by Scenario							
	Base Load					HLBFMC	LLBFMC
	BLBFMC	BLBFNC	BLBFHC	BLHFMC	BLLFMC		
Repower Maximum	$ 28,101	$ 28,278	$ 27,836	$ 37,708	$ 22,968	$ 29,454	$ 26,569
Repower Moderate	$ 28,541	$ 28,705	$ 28,303	$ 37,518	$ 23,819	$ 29,892	$ 27,021
Repower Minimum	$ 28,534	$ 28,696	$ 28,298	$ 37,449	$ 23,835	$ 29,881	$ 27,010
No Repower	$ 28,610	$ 28,778	$ 28,361	$ 37,704	$ 23,717	$ 29,950	$ 27,098

28-year PWRR Differential ($ millions) by Scenario							
	Base Load					HLBFMC	LLBFMC
	BLBFMC	BLBFNC	BLBFHC	BLHFMC	BLLFMC		
Repower Maximum	$ -	$ -	$ -	$ 259	$ -	$ -	$ -
Repower Moderate	$ 440	$ 427	$ 467	$ 69	$ 851	$ 438	$ 452
Repower Minimum	$ 434	$ 418	$ 462	$ -	$ 867	$ 428	$ 441
No Repower	$ 509	$ 501	$ 525	$ 254	$ 749	$ 496	$ 530

28-year PWRR Ranking by Scenario							
	Base Load					HLBFMC	LLBFMC
	BLBFMC	BLBFNC	BLBFHC	BLHFMC	BLLFMC		
Repower Maximum	1	1	1	4	1	1	1
Repower Moderate	3	3	3	2	3	3	3
Repower Minimum	2	2	2	1	4	2	2
No Repower	4	4	4	3	2	4	4

The buildouts for each plan were not modified for any of the scenarios analyzed.

The key findings of the 20-year and study period PWRR analysis are summarized below:

- The Repower Maximum Plan is the least cost plan of the alternative plans in all but the high fuel price scenario. While this plan has relatively high capital costs, given both the high contribution to the Companies' capacity need and the relatively low operating costs, the low-cost result is logical.
- The Repower Moderate Plan is the second most expensive plan of the alternative plans in all but the high fuel price scenario.
- The Repower Minimum Plan is the second lowest cost plan of the alternative plans in most scenarios. It is least cost in the high fuel scenario and highest cost in the low fuel scenario. It adds the least capacity but is also the least capital intensive.

- The study period PWRR for the Repower Minimum and Repower Moderate Plans are within two tenths of a percent of each other in all scenarios.
- The study period PWRR for the Repower Minimum and No Repower Plans are within seven tenths of a percent of each other in all scenarios.

G. Environmental Externalities and Net Economic Benefits

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

1. OVERVIEW OF RELEVANT REGULATIONS

The regulations require the Companies to rank power supply options on the basis of the Present Worth of Revenue Requirement ("PWRR") and the Present Worth of Societal Costs ("PWSC"). The PWSC of a resource plan is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility…."[63] 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."[64] 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."[65]

The regulations also require the Companies to assess the "net economic benefits" of plans under certain circumstances, as noted below. "Economic benefits" are often referred to as "economic impacts," so that they are distinguished from other types of benefits. The net economic benefits include both the positive impacts 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.

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[63] NAC § 704.937(4).

[64] NAC § 704.9359.

[65] *Id.*

The Companies retained the services of NERA Economic Consulting ("NERA") to provide analyses of the environmental costs and net economic benefits for the four alternative resource plans for the Amendment.[66] Details on NERA's analyses of the Fifth Amendment plans are provided in the NERA Report (Technical Appendix Item ECON-9).

2. CARBON DIOXIDE POLICY USED IN THESE ANALYSES

NERA developed three carbon dioxide ("CO_2") policy scenarios for the Fifth Amendment plans that reflect two 2022 federal policy changes, with the "Mid CO_2 Policy" scenario used for the results presented here. In analyses prior to the Fourth Amendment, NERA had developed scenarios that assumed establishment of a national cap-and-trade program to regulate electric utility CO_2 emissions under Section 111(d) of the Clean Air Act, resulting in trajectories for CO_2 allowance prices. But on June 30, 2022, the Supreme Court ruled that Section 111(d) does not provide the U.S. Environmental Protection Agency ("EPA") with the authority to regulate CO_2 emissions based on "generation shifting" as would occur under a cap-and-trade program. Thus, the assumption of a future cap-and-trade program is no longer appropriate.

The second major recent federal climate policy development is passage of the Inflation Reduction Act ("IRA") in August 2022. The IRA includes federal tax credits for new renewable and clean energy electricity projects, for existing nuclear generation from merchant generators, for new residential clean energy projects, and for new residential energy efficiency projects. NERA developed a full set of results for the Mid CO_2 Policy scenario based upon their modeling estimates of how these various IRA tax credit programs will affect the trajectories of natural gas and coal prices. The Companies used these estimated effects on fuel prices in its PLEXOS modeling of the Fifth Amendment plans. Results were also developed for the two other NERA CO_2 policy scenarios, the Low CO_2 Policy scenario and the High CO_2 Policy scenario.

3. ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS

NERA uses a damage value approach to develop estimates of the environmental costs of conventional and toxic air emissions. This approach begins with the premise that the conceptually correct measure of the value of pollutant emissions is equal to the value of the damages caused by those emissions (assuming no binding cap-and-trade program or other price for emissions).

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

Damages can include effects on health, visibility, and agriculture.[67] 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 Fifth Amendment plans. The figure shows environmental costs for emissions controlled to meet National Ambient Air Quality Standards ("NAAQS") as well as emissions related to requirements of the Mercury and Air Toxics Standards ("MATS") issued by EPA in 2011. Based on the NAAQS, NERA included values for emissions of nitrogen oxides ("NO_X"), particulate matter ("PM"), volatile organic compounds ("VOC"), carbon monoxide ("CO"), and sulfur dioxide ("SO_2"). VOC environmental costs are estimated to be $0 because they do not contribute to ambient ozone concentrations in Nevada, as discussed in the NERA Report. CO is not monetized because the requisite air quality modeling data are unavailable; however, CO emissions projections are included in the NERA Report. As noted in the NERA Report, the national SO_2 cap is not expected to be binding and, thus, costs from SO_2 emissions are evaluated based on damage values like other air emissions (rather than modeled as covered by a cap-and-trade program as in some past IRPs). Based on their inclusion in the MATS regulation, emissions of mercury and hydrogen chloride ("HCl") are also included. The MATS regulation uses PM emissions as a proxy for non-mercury metallic air toxics, but this element of the MATS regulation does not lead to additional environmental costs because PM emissions are already included based upon the NAAQS. HCl is not monetized because EPA does not provide the relevant information in the MATS regulatory impact analysis; however, HCl emission projections are included in the NERA Report. NERA does not expect that including costs for the other pollutants, if they could be estimated, would have any significant effects on the estimates of the environmental costs of conventional and toxic air emissions.

[67] 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, 2024-2051 (2024$ MILLIONS)

	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
NOx	$2.41	$2.43	$2.47	$2.38
PM	$30.54	$30.90	$31.71	$30.10
VOC	$0.00	$0.00	$0.00	$0.00
CO	--	--	--	--
SO2	$7.02	$7.03	$7.23	$7.13
Mercury	$0.00	$0.00	$0.00	$0.00
HCl	--	--	--	--
Total	**$39.97**	**$40.36**	**$41.41**	**$39.62**

Notes: All values are present values as of 2024 in millions of 2024 dollars for the period 2024-2051 using inflation rate information provided by the Companies and nominal annual discount rates of 7.14 percent for Nevada Power and 6.95 percent for Sierra. Total may differ from the sum of the rows due to independent rounding. "-" denotes that the environmental costs of the air emission or air toxic are not monetized. The costs of VOC emissions are zero because of evidence that these emissions do not contribute to urban ozone, the relevant damage category. The costs of mercury emissions are non-zero but round to $0.00 in millions for all four plans.

Source: NERA calculations as explained in text.

Figure NERA-2 shows the differences in environmental costs for conventional and toxic air emissions for the other Fifth Amendment plans relative to the Repower Minimum Plan, the Preferred Plan. Compared to the Repower Minimum Plan (Preferred Plan), environmental costs of conventional and toxic air emissions are slightly greater for the Repower Moderate Plan (about 1 percent), somewhat greater for the Repower Maximum Plan (about 4 percent), and slightly smaller for the No Repower Plan (about 1 percent).

FIGURE NERA-2. DIEFFERENCES IN PRESENT VALUES OF ENVIRONMENTAL COSTS OF CONVENTIONAL AND TOXIC AIR EMISSIONS RELATIVE TO THE REPOWER MINIMUM PLAN (PREFERRED PLAN), 2024-2051 (2024$ MILLIONS)

	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
NOx	--	$0.02	$0.06	-$0.03
PM	--	$0.36	$1.17	-$0.43
VOC	--	$0.00	$0.00	$0.00
CO	--	--	--	--
SO2	--	$0.01	$0.21	$0.11
Mercury	--	$0.00	$0.00	$0.00
HCl	--	--	--	--
Total	**–**	**$0.39**	**$1.44**	**-$0.35**

Notes: All values are present values as of 2024 in millions of 2024 dollars for the period 2024-2051 using inflation rate information provided by the Companies and nominal annual discount rates of 7.14 percent for Nevada Power and 6.95 percent for Sierra. Total may differ from the sum of the rows due to independent rounding. "-" denotes that the environmental costs of the air emission or air toxic are not monetized. The costs of VOC emissions are zero because of evidence that these emissions do not contribute to urban ozone, the relevant damage category.

Source: NERA calculations as explained in text.

4. SOCIAL COST OF CARBON FOR CARBON DIOXIDE EMISSIONS

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

a. ESTIMATES OF CARBON DIOXIDE EMISSIONS

NERA developed estimates of CO_2 emissions over the period from 2024 to 2051 for the Fifth Amendment plans using information from modeling done by the Companies and from other sources. Figure NERA-3 provides these estimates of CO_2 emissions for the Fifth Amendment plans, with Figure NERA-4 showing percent differences for the three other Fifth Amendment plans relative to the Repower Minimum Plan, the Preferred Plan. Compared to the Repower Minimum Plan (Preferred Plan), the annual CO_2 emissions are larger in the Repower Moderate Plan, the Repower Maximum Plan, and the No Repower Plan.

FIGURE NERA-3. CARBON DIOXIDE EMISSIONS, 2024-2051 (MILLIONS OF METRIC TONS)

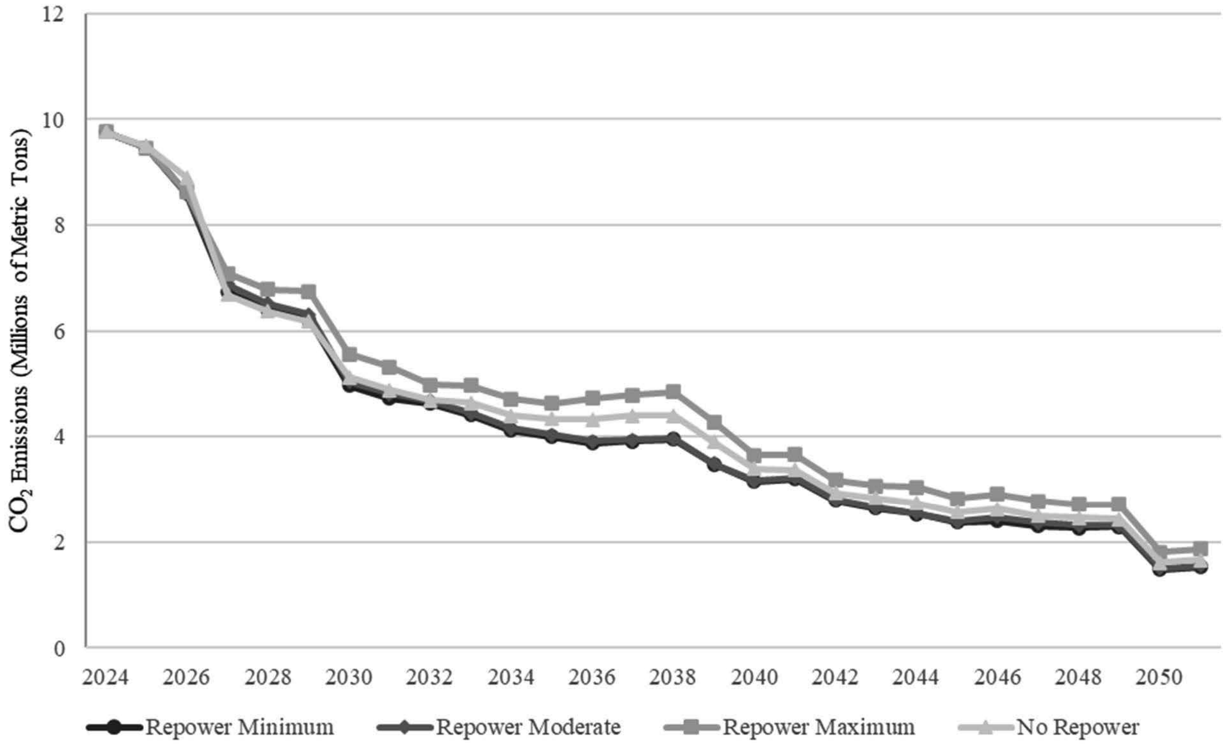
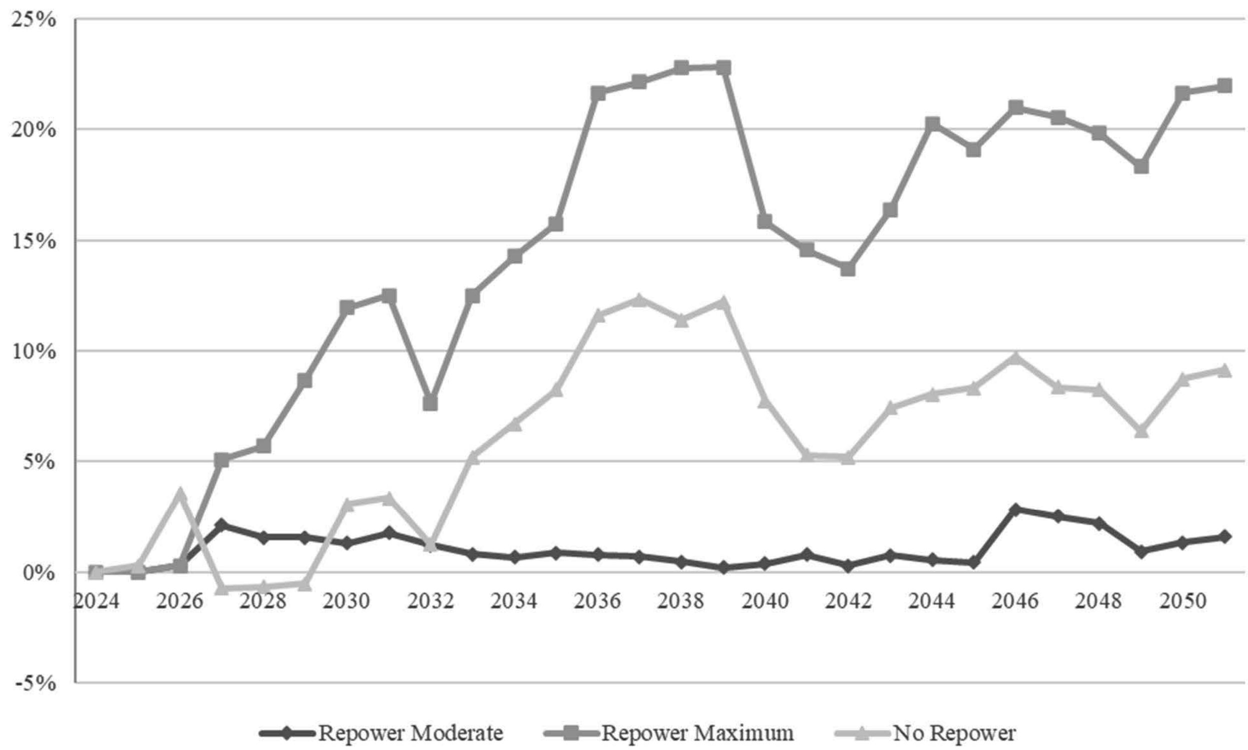


FIGURE NERA-4. PERCENTAGE DIFFERENCE IN CARBON DIOXIDE EMISSIONS RELATIVE TO THE REPOWER MINIMUM PLAN (PREFERRED PLAN), 2024-2051



b. METHODOLOGY REQUIRED BY THE COMMISSION TO VALUE CARBON DIOXIDE EMISSIONS

Subsection 5 of the Commission's August 2018 Order requires the following determination of the social cost of carbon. "[T]he social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the 'Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis' released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016."[68]

[68] There is some potential confusion in use of the term "social cost of carbon." The term is used by the Interagency Working Group (as well as many commentators) to refer to its estimates; but these estimates are referred to by the Commission in its August 2018 Order as the "future global economic costs." The Commission, in its August 2018 Order, refers to the social cost of carbon as the difference between future global economic costs and the costs internalized as private costs. NERA adopts the terminology of the August 2018 Order in its current report (although some previous reports have used "social cost of carbon" to refer to the values developed by the Interagency Working Group). The NERA Report provides information on the methodology used by the Interagency Working Group to develop its estimates and on the wide range of estimates that are provided in the February 2021 report, which updates the August 2016 report for inflation.

The Interagency Working Group provided estimates of the present value of future global economic costs from an additional annual ton of CO_2 for three discount rates—2.5 percent, 3 percent, and 5 percent—using the average of the damages distribution it calculated from modeling results. It also provided a fourth set of global economic costs based on the 3 percent discount rate and the 95th percentile of the damages distribution, which it noted are designed to represent impacts from temperature change further out in the tails of the global economic cost distribution. These four sets of values cover a very large range and, indeed, the full range of values reported by the Interagency Group was much greater than these four sets of estimates.

Because the carbon policy scenarios developed by NERA do not result in internalization of any environmental costs related to CO_2 emissions as private costs, NERA calculated the social cost of carbon based on the global environmental cost values in the most recent report of the Interagency Working Group (Interagency Working Group 2021), using the values based on a 3 percent discount rate and the average of the damages distribution.

c. Social Costs of Carbon

Figure NERA- 5 shows the estimates of the present values of the social costs of carbon for the Fifth Amendment plans, and Figure NERA-6 shows the difference in the social costs of carbon for the other Fifth Amendment plans relative to the Repower Minimum Plan, the Preferred Plan. Compared to the Repower Minimum Plan (Preferred Plan), the social costs of carbon are slightly greater for the Repower Moderate Plan (about 1 percent) and somewhat greater for the Repower Maximum Plan and No Repower Plan (about 10 percent and 4 percent, respectively).

FIGURE NERA-5. PRESENT VALUES OF SOCIAL COSTS OF CARBON, 2024-2051 (2024$ MILLIONS)

Repower Minimum	Repower Moderate	Repower Maximum	No Repower
$6,609	$6,667	$7,300	$6,889

Notes: All values are present values as of 2024 in millions of 2024 dollars for the period 2024-2051 using the social cost of carbon values from the Interagency Working Group based upon a 3 percent discount rate and the average damages distribution.
Source: NERA calculations as explained in text.

FIGURE NERA-6. DIFFERENCES IN PRESENT VALUES OF SOCIAL COSTS OF CARBON, RELATIVE TO THE REPOWER MINIMUM PLAN (PREFERRED PLAN), 2024-2051 (2024$ MILLIONS)

Repower Minimum	Repower Moderate	Repower Maximum	No Repower
-	$58	$692	$280

Notes: All values are present values as of 2024 in millions of 2024 dollars for the period 2024-2051 using the social cost of carbon values from the Interagency Working Group based upon a 3 percent discount rate and the average damages distribution.
Source: NERA calculations as explained in text.

NERA has in prior IRPs noted that the global values developed by the Interagency Working Group are not comparable to the environmental costs calculated for conventional and toxic air emissions for several reasons: (a) the Interagency Working Group values are more uncertain partly because they are based upon impacts in the distant future; (b) the Interagency Working Group values are based on different discount rates than the private (NV Energy) discount rates used to calculate the present value of environmental costs; and (c) the Interagency Working Group values are based upon global damages rather than U.S. damages.

5. EXTERNAL ENVIRONMENTAL COSTS OF WATER CONSUMPTION

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

Figure NERA- 7 shows the estimated external environmental costs of water consumption (i.e., the added costs beyond those already included in the PWRR) for the Fifth Amendment plans, and Figure NERA-8 shows the differences between the other Fifth Amendment plans relative to the Repower Minimum Plan, the Preferred Plan. All values are calculated as present values over the 28-year period from 2024 to 2051 as of 2024. Compared to the Repower Minimum Plan (Preferred Plan), the external environmental water costs are slightly greater for the Repower Moderate Plan (less than 1 percent), slightly lower for the Repower Maximum Plan (less than 1 percent), and somewhat greater for the No Repower Plan (about 17 percent).

FIGURE NERA-7. PRESENT VALUES OF EXTERNAL ENVIRONMENTAL WATER COSTS, 2024-2051 (2024$ MILLIONS)

Repower Minimum	Repower Moderate	Repower Maximum	No Repower
$18.39	$18.45	$18.23	$15.18

Notes: All values are present values as of 2024 in millions of 2024 dollars for the period 2024-2051 using inflation rate information provided by the Companies and nominal annual discount rates of 7.14 percent for Nevada Power and 6.95 percent for Sierra.

Source: NERA calculations as explained in text.

FIGURE NERA-8. DIFFERENCES IN PRESENT VALUES OF EXTERNAL ENVIRONMENTAL WATER COSTS RELATIVE TO THE REPOWER MINIMUM PLAN (PREFERRED PLAN), 2024-2051 (2024$ MILLIONS)

Repower Minimum	Repower Moderate	Repower Maximum	No Repower
-	$0.05	-$0.16	-$3.21

Notes: All values are present values as of 2024 in millions of 2024 dollars for the period 2024-2051 using inflation rate information provided by the Companies and nominal annual discount rates of 7.14 percent for Nevada Power and 6.95 percent for Sierra.

Source: NERA calculations as explained in text.

6. OTHER ENVIRONMENTAL EFFECTS

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

7. PRESENT WORTH OF SOCIETAL COST

Figure NERA-9 provides estimates of the PWSC for the Fifth Amendment resource plans. As noted above, PWSC is defined as the sum of the PWRR and the environmental costs. Figure NERA-10 shows the PWSC values for the other Fifth Amendment plans relative to the Repower Minimum Plan, the Preferred Plan. Compared to the Repower Minimum Plan (Preferred Plan), the Repower Moderate Plan has a slightly greater PWSC (about $66 million, or about 0.2 percent), the Repower Maximum Plan has a somewhat greater PWSC (about $259 million, or about 1 percent), and the No Repower Plan has a somewhat greater PWSC (about $353 million, or about 1 percent).

FIGURE NERA-9. PRESENT WORTH OF SOCIETAL COSTS, 2024-2051 (2024$ MILLIONS)

	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
PWRR	$28,534.5	$28,541.3	$28,100.8	$28,610.2
Conventional Air Emission Costs	$40.0	$40.4	$41.4	$39.6
External Water Costs	$18.4	$18.4	$18.2	$15.2
Social Costs of Carbon	$6,608.6	$6,666.8	$7,300.3	$6,888.9
PWSC	$35,201.4	$35,266.9	$35,460.8	$35,553.9

Notes: All values are present values as of 2024 in millions of 2024 dollars for the period 2024-2051. Values other than the social costs of carbon are based on inflation information provided by the Companies and nominal annual discount rates of 7.14 percent for Nevada Power and 6.95 percent for Sierra. Social cost of carbon values use the Interagency Working Group case based upon a 3 percent discount rate and the average damages distribution.

Source: NERA calculations as explained in text.

FIGURE NERA-10. DIFFERENCES IN PRESENT WORTH OF SOCIETAL COSTS RELATIVE TO THE REPOWER MINIMUM PLAN (PREFERRED PLAN), 2024-2051 (2024$ MILLIONS)

	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
PWRR	-	$6.8	-$433.7	$75.7
Conventional Air Emission Costs	-	$0.4	$1.4	-$0.4
External Water Costs	-	$0.1	-$0.2	-$3.2
Social Costs of Carbon	-	$58.3	$691.8	$280.3
PWSC	-	$65.5	$259.4	$352.5

Notes: All values are present values as of 2024 in millions of 2024 dollars for the period 2024-2051. Values other than the social costs of carbon are based on inflation information provided by the Companies and nominal annual discount rates of 7.14 percent for Nevada Power and 6.95 percent for Sierra. Social cost of carbon values use the Interagency Working Group case based upon a 3 percent discount rate and the average damages distribution.

Source: NERA calculations as explained in text.

8. ECONOMIC IMPACTS

NERA used the economic model developed by Regional Economic Models, Inc. ("REMI") to develop comprehensive estimates of economic impacts for Fifth Amendment plans. The Companies provided NERA with information on the Fifth Amendment plans that, together with some other information, enabled NERA to estimate both the positive economic impacts of expenditures in Nevada for the Fifth Amendment resource plans and the negative economic impacts of the electricity revenue requirements for the Fifth Amendment resource plans. These analyses are based primarily on the costs and revenue requirements related to the Companies' bundled customers and do not include costs and revenues related to entities that purchase transmission capacity from the Companies ("transmission-only customers"), as the PWRR cost information generally is based on bundled customers. The only exception is that the costs and revenue requirements include those related to provision of 90 MW of additional reserve capacity for transmission-only customers, information that is included in the PWRR.

9. REMI MODEL

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

Simulations of the economy in REMI require a "baseline" plan to which alternative plans can be compared. The Companies developed a Base Case that is assumed to reflect the REMI baseline or reference case. The economic impact analysis was conducted over the period from 2024 to 2051, which is the period over which the Companies forecast expenditures and revenues. NERA developed economic impact assessments for the Fifth Amendment plans relative to the Base Case. Although the Base Case is assumed to be the baseline or reference case for purposes of the REMI modeling, results are presented for the other Fifth Amendment plans relative to the Repower Minimum Plan (the Preferred Plan), the same format as for the environmental cost comparisons.

a. EXPENDITURES, REVENUES AND ECONOMIC IMPACTS

Figure NERA- 11 shows the average annual expenditures in Nevada under the Fifth Amendment plans and the Base Case. The table includes construction expenditures, fuel expenditures and non-fuel operating and maintenance ("O&M") expenditures. Only expenditures in Nevada are included in these calculations because the objective is to estimate the economic impacts in Nevada, and expenditures outside Nevada are unlikely to contribute significantly to the Nevada economy. Note that these average annual values do not reflect differences over the 28-year period, differences that are included in the REMI modeling. As discussed in the NERA Report, the expenditures exclude certain categories of expenditures, such as market purchases by the Companies, because those expenditures are assumed to be from power producers outside Nevada (and thus the expenditures would not generate significant positive economic impacts in Nevada). The NERA analysis assumes that 50 percent of expenditures related to the open position would occur within the state and that 50 percent of these expenditures would occur outside Nevada.

FIGURE NERA-11. AVERAGE ANNUAL EXPENDITURES IN NEVADA, 2024-2051 (2024$ MILLIONS)

	Base	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
Construction	$1,660	$1,753	$1,782	$1,717	$1,769
Fuel	$321	$322	$324	$365	$335
O&M	$518	$506	$515	$468	$490
Total	**$2,500**	**$2,581**	**$2,621**	**$2,550**	**$2,594**

Note: All values are average annual values over the period from 2024 to 2051 in millions of 2024 dollars. Dollar year conversions are based on inflation rate information provided by the Companies.

Source: NERA calculations as explained in text.

Figure NERA-12 shows the differences in average annual expenditures in Nevada over the period from 2024 to 2051 for the Fifth Amendment resource plans relative to the Base Case. The differences in each year relative to the Base Case are the values that are included in the REMI modeling, based upon detailed information to reflect the sectors directly affected by the expenditures in Nevada in each year.

FIGURE NERA-12. AVERAGE ANNUAL EXPENDITURES IN NEVADA RELATIVE TO THE BASE CASE, 2024-2051 (2024$ MILLIONS)

	Base	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
Construction	-	$93	$121	$57	$109
Fuel	-	$1	$3	$44	$14
O&M	-	-$13	-$4	-$51	-$29
Total	**-**	**$81**	**$121**	**$50**	**$94**

Note: All values are average annual values over the period from 2024 to 2051 in millions of 2024 dollars. Dollar year conversions are based on inflation rate information provided by the Companies.

Source: NERA calculations as explained in text.

Figure NERA-13 shows the average annual electricity revenue requirements for 2024-2051, apportioned by customer class. The values by customer class are based on the methodology described in the NERA Report that includes information for Nevada Power and Sierra.

FIGURE NERA-13. AVERAGE ANNUAL ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS, 2024-2051 (2024$ MILLIONS)

	Base	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
Residential	$1,133	$1,133	$1,132	$1,111	$1,134
Commercial	$546	$546	$546	$536	$546
Industrial	$212	$212	$212	$208	$212
Total	**$1,891**	**$1,891**	**$1,890**	**$1,855**	**$1,892**

Note: All values are average annual values over the period from 2024 to 2051 in millions of 2024 dollars. Dollar year conversions are based on inflation rate information provided by the Companies.
Source: NERA calculations as explained in text.

Figure NERA-14 shows differences in the average annual electricity revenue requirements for the four Fifth Amendment plans relative to the Base Case, which is assumed to be consistent with the REMI baseline. The differences in each year are the values that are included in the REMI modeling, based on detailed information to reflect the direct impacts on the three sets of customers in each year.

FIGURE NERA-14. ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS RELATIVE TO THE BASE CASE, 2024-2051 (2024$ MILLIONS)

	Base	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
Residential	-	$0	-$1	-$22	$2
Commercial	-	$0	$0	-$10	$0
Industrial	-	$0	$0	-$4	$0
Total	**-**	**$0**	**-$2**	**-$36**	**$1**

Note: All values are average annual values over the period from 2024 to 2051 in millions of 2024 dollars. Dollar year conversions are based on inflation rate information provided by the Companies.
Source: NERA calculations as explained in text.

REMI modeling takes as inputs the annual expenditures in Nevada and the annual electricity revenue requirements—both relative to the Base Case—and develops estimates of the economic impacts in Nevada for the Fifth Amendment plans over time. The NERA Report describes the methodologies that are used to translate the expenditure and revenue requirement categories into the annual REMI inputs that NERA uses when it runs the REMI model over the 28-year period from 2024-2051.

Figure NERA-15 provides estimates of the differences in four economic outcome measures for selected years in Nevada for the Fifth Amendment plans relative to the Base Case. The measures include gross state product, personal income, state and local tax revenues, and employment (total jobs). The economic impacts of the Fifth Amendment plans vary over the selected years in the 28-year period from 2024-2051, reflecting the different timing of construction and other major initial changes in economic activity under the different Fifth Amendment plans.

FIGURE NERA-15. ECONOMIC IMPACTS IN NEVADA FOR SELECTED YEARS RELATIVE TO THE BASE CASE, 2024-2051

	Nevada Economic Impact						
	2024	2025	2026	2027	2037	2047	2051
Base							
Gross State Product (millions of 2024 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2024 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2024 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
Repower Minimum							
Gross State Product (millions of 2024 dollars)	19	117	428	41	-58	-14	56
Personal Income (millions of 2024 dollars)	12	73	265	10	-39	-11	31
State & Local Tax Revenue (millions of 2024 dollars)	1	7	25	1	-4	-1	3
Employment (total jobs)	164	1,009	3,639	314	-417	-118	383
Repower Moderate							
Gross State Product (millions of 2024 dollars)	61	257	433	93	-54	-3	65
Personal Income (millions of 2024 dollars)	38	161	261	44	-31	3	42
State & Local Tax Revenue (millions of 2024 dollars)	4	15	25	4	-3	0	4
Employment (total jobs)	531	2,240	3,642	699	-365	-36	433
Repower Maximum							
Gross State Product (millions of 2024 dollars)	61	275	508	-203	-93	-6	40
Personal Income (millions of 2024 dollars)	38	171	305	-154	-59	-9	21
State & Local Tax Revenue (millions of 2024 dollars)	4	16	29	-14	-6	-1	2
Employment (total jobs)	531	2,383	4,266	-1,734	-758	-217	174
No Repower							
Gross State Product (millions of 2024 dollars)	42	142	50	-109	-3	-1	-6
Personal Income (millions of 2024 dollars)	26	89	27	-75	-2	-1	-5
State & Local Tax Revenue (millions of 2024 dollars)	2	8	3	-7	0	0	0
Employment (total jobs)	367	1,250	452	-913	-56	-46	-59

Notes: The Base Case is assumed to be consistent with the REMI baseline, and thus results are reported relative to the Base Case.
Employment values include full time and part time jobs.
Sources: REMI; NERA calculations as explained in text.

Figure NERA-16 provides estimates of the average annual economic impacts in Nevada—based on the four impact measures—over the 28-year period from 2024-2051 for the other Fifth Amendment plans relative to the Repower Minimum Plan, the Preferred Plan. Relative to the Repower Minimum Plan (Preferred Plan), all four average annual economic impacts in Nevada are somewhat larger for the Repower Moderate Plan, somewhat smaller for the Repower Maximum Plan, and very similar for the No Repower Plan.

FIGURE NERA-16. ANNUAL AVERAGE ECONOMIC IMPACTS IN NEVADA RELATIVE TO THE REPOWER MINIMUM PLAN (PREFERRED PLAN)

	Repower Minimum	Repower Moderate	Repower Maximum	No Repower
Gross State Product (millions of 2024 dollars)	-	17	-7	4
Personal Income (millions of 2024 dollars)	-	15	-9	0
State & Local Tax Revenue (millions of 2024 dollars)	-	1	-1	0
Employment (total jobs)	-	141	-155	-1

Notes: Employment values include full time and part time jobs.
Sources: REMI; NERA calculations as explained in text.

H. Selection of the Preferred Plan

The following criteria were used when selecting the Repower Minimum Plan as the Preferred Plan and the Repower Moderate Plan as the Alternate Plan.

Need for a complete Valmy solution
All of the alternative plans allow for the retirement of coal-fired generation at Valmy and meet the requirements for voltage support and available around-the-clock generation in the Carlin Trend load pocket. Only the plans that include a repowered Valmy achieve the retirement of coal combustion by the end of 2025 as previously targeted. Continuing coal combustion past 2025 involves certain risks presented in the Generation Section. The plans that include repowering Valmy achieve this solution with minimal capital expenditure.

Capacity and RPS need due to peviously approved project cancellation
The Companies have lost approved planned capacity, energy, and RPS contribution due to cancellation of the Southern Bighorn and Chuckwalla PV/BESS projects and delay of the Boulder Solar III PV/BESS project. All the alternative plans provide incremental capacity to varying degrees as well as RPS contribution in the form of the Sierra Solar PV/BESS project. The presence of the Valmy BESS tends to decrease the amount of solar overgeneration in a given case.

Intent to reduce the risk of exposure to the uncertain availability of market capacity, simultaneously advancing resource sufficiency as required for participation in WRAP or a future market or regional transmission organization ("RTO")

As described in the introduction to this Fifth Amendment, recent events and reports contribute to ever decreasing confidence in the availability of market capacity. While the 2021 Joint IRP, and First and Fourth Amendments reduced the reliance on market capacity relative to prior plans, continued focus in this area is required to reduce risk and ensure resource adequacy. This Fifth Amendment continues addressing these concerns regarding the availability of market capacity as it is impacted by changes in climate, weather, and resource variability across the region. As described in Section 1, these efforts simultaneously contribute to the resource sufficiency requirements of WRAP that are also expected of a future regional market or RTO. While all four plans proposed in this Amendment reduce the near-term exposure to uncertain market capacity by continuing operation of existing resources and adding new resources, the Repower Maximum Plan adds the most near-term capacity, followed by the No Repower Plan, then the Repower Moderate Plan, and lastly the Repower Minimum Plan. The Repower Minimum Plan adds modest incremental capacity while limiting the scope of this Amendment and the required capital expenditures.

PWRR and PWSC results

The Repower Maximum Plan has the lowest PWRR in most scenarios due, in part, to the low operating cost of firm dispatchable resources to meet – but not exceed – the energy needs of the Companies. However, the PWSC of this plan is the second highest of the alternative plans, due to its higher social cost of carbon.

The Repower Minimum Plan has a higher PWRR than the Repower Maximum Plan in most scenarios, but has the lowest PWSC of the four plans, followed closely by the Repower Moderate Plan. The PWRR and PWSC for the Repower Minimum and Repower Moderate plans differ by less than two tenths of one percent.

The No Repower Plan has the highest PWRR in most scenarios and the highest PWSC.

The Companies' and state's decarbonization goals

All of the alternative plans presented in this amendment add renewable resources in the form of the Sierra Solar PV/BESS project and target the Companies' proportionate contribution to the state's 2050 clean energy goal as shown in Figure EA-32. The Repower Minimum and Repower Moderate Plans have the same amount of installed CO_2-producing capacity. These plans have the lowest CO_2 intensity amongst the four plans, with the Repower Minimum Plan having slightly lower CO_2 intensity, as shown in Figure EA-30. These differences are reflected in the social costs of carbon for the plans.

Based on the criteria and discussion presented, the Companies selected the Repower Minimum Plan as the Preferred Plan and the Repower Moderate Plan as the Alternate Plan. While all plans provide a complete Valmy solution, the Repower Minimum Plan balances incremental capacity and RPS contribution with overall cost and decarbonizing goals.

The average cost of generation for the Preferred Plan is contained in Technical Appendix ECON-3.

I. Loads and Resources Tables

NAC § 704.945 requires a table of loads and resources for each alternative plan analyzed. For the Preferred Plan, the 20-year projection of 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-36. 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.

For this Fifth Amendment, the classification of resources has been changed. The classification is intended to sort resources into meaningful groups. In past filings, BESS resources were grouped with renewable resources; now BESS is no longer grouped with renewables and BESS that charge stictly from PV is grouped separately from BESS that can be charged from any resource.

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 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 Companies' contribution to the state's 2050 clean energy goal.

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

Combined L&R Table. Figure EA-36 provides the L&R table for the Preferred Plan under the Base Load scenario.

FIGURE EA-36
L&R TABLE
PREFERRED PLAN
(2024-2041)

1		NV Energy																	
2		LOADS AND RESOURCES TABLE																	
3		*repower Valmy + SS + T45*																	
4		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**
5	Gross Peak	8,639	8,872	8,975	9,173	9,363	9,559	9,694	9,838	9,977	10,114	10,259	10,378	10,489	10,595	10,724	10,827	10,956	11,060
6	DSM	123	165	202	251	287	329	363	408	451	487	523	542	545	542	568	563	569	565
7	Private Generation	103	140	175	211	221	274	300	323	344	364	361	426	446	470	498	509	550	574
8	Avoided Capacity	175	181	178	182	191	182	179	180	183	193	196	173	171	170	172	188	169	160
9	Forecast System Peak	8,237	8,386	8,419	8,529	8,665	8,774	8,851	8,927	8,999	9,070	9,178	9,237	9,327	9,412	9,487	9,568	9,668	9,762
10	Sales Obligations																		
11	**NET System Peak**	8,237	8,386	8,419	8,529	8,665	8,774	8,851	8,927	8,999	9,070	9,178	9,237	9,327	9,412	9,487	9,568	9,668	9,762
12	Planning Reserves (16%)	1,318	1,342	1,347	1,365	1,386	1,404	1,416	1,428	1,440	1,451	1,468	1,478	1,492	1,506	1,518	1,531	1,547	1,562
13	**REQUIRED RESOURCES**	9,555	9,728	9,766	9,894	10,051	10,178	10,267	10,355	10,439	10,521	10,646	10,715	10,819	10,918	11,005	11,099	11,215	11,324
14	OATT Reserves	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
15	**AVAILABLE RESOURCES**	8,635	8,636	8,946	9,356	9,507	9,924	10,031	10,020	10,010	10,043	10,190	10,251	10,359	10,574	10,617	10,507	10,673	10,689
16	OPEN Position	920	1,092	820	538	544	254	236	335	429	478	456	464	460	344	388	592	542	635
17	OPEN/(LONG) Position	920	1,092	820	538	544	254	236	335	429	478	456	464	460	344	388	592	542	635
19	Company	(All)																	
21	**Sum of Value**	**Column Labels**																	
22	**Row Labels**	**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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	**NVE.existing.Gas**	6,386	6,386	6,386	6,386	6,386	6,386	6,386	6,386	6,386	6,386	6,386	6,386	6,332	6,332	6,332	6,044	6,044	6,044
26	**NVE.existing.other**	5	5	5	5	5	-	-	-	-	-	-	-	-	-	-	-	-	-
27	**NVE.existing.other.BESS**	230	223	217	210	200	183	190	191	191	197	197	197	189	177	178	170	165	166
28	**NVE.existing.Renewable.PV**	39	41	42	36	35	34	27	27	27	25	25	24	22	22	21	21	20	18
29	**NVE.existing.Renewable.WH**	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
30	**NVE.existing.solar.BESS**	100	97	94	91	87	79	83	83	83	85	85	86	82	77	77	74	72	72
31	**PPA.existing.other**	97	12	12	12	12	12	12	12	-	-	-	-	-	-	-	-	-	-
32	**PPA.existing.Renewable.CSP**	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	**PPA.existing.Renewable.GEO**	187	197	208	227	229	240	189	189	179	124	124	124	124	124	119	119	119	119
34	**PPA.existing.Renewable.HYDRO**	140	129	128	125	121	119	119	119	119	119	119	119	119	119	119	119	119	119
35	**PPA.existing.Renewable.LFG**	9	9	9	9	9	9	9	9	9	-	-	-	-	-	-	-	-	-
36	**PPA.existing.Renewable.PV**	606	664	665	556	544	529	431	431	427	378	378	370	351	331	272	256	245	239
37	**PPA.existing.Renewable.WIND**	20	20	20	20	20	20	20	20	20	-	-	-	-	-	-	-	-	-
38	**PPA.existing.solar.BESS**	590	627	556	537	511	467	487	468	469	480	480	482	465	433	332	319	308	310
39	**existing Total**	8,725	8,726	8,397	8,269	8,164	8,083	7,958	7,940	7,915	7,799	7,799	7,793	7,689	7,620	7,455	7,127	7,097	7,087
40	**placeholder**																		
41	**NVE.placeholder.other**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	**NVE.placeholder.other.BESS**	-	-	-	-	-	405	422	424	425	435	435	437	652	975	1,088	1,315	1,520	1,529
43	**NVE.placeholder.renewable.PV**	-	-	-	105	146	185	370	370	382	473	473	486	523	560	631	663	688	700
44	**NVE.placeholder.solar.BESS**	-	-	-	411	626	690	719	723	725	742	742	744	718	667	672	645	622	627
45	**PPA.placeholder.renewable.WIND**	-	-	-	-	-	-	-	-	-	29	177	226	226	226	245	245	245	245
46	**placeholder Total**	-	-	-	516	772	1,280	1,511	1,517	1,532	1,679	1,827	1,893	2,119	2,428	2,636	2,868	3,075	3,101
47	**Proposed**																		
48	**NVE.Proposed.GAS**																		
49	SPPC 1-repower Valmy_26	-	-	261	261	261	261	261	261	261	261	261	261	261	261	261	261	261	261
50	**NVE.Proposed.GAS Total**	-	-	261	261	261	261	261	261	261	261	261	261	261	261	261	261	261	261
51	**NVE.Proposed.renewable.PV**																		
52	SPPC 400 MW Sierra Solar PV_27	-	-	-	31	30	29	24	24	24	21	21	21	20	19	18	18	17	17
53	NPC 400 MW Sierra Solar PV_27	-	-	-	46	45	44	36	36	35	31	31	31	30	29	28	26	26	25
54	**NVE.Proposed.renewable.PV Total**	-	-	-	77	75	73	60	60	59	52	52	52	50	48	46	44	43	42
55	**NVE.Proposed.solar.BESS**																		
56	SPPC 400 MW Sierra Solar BESS_26	-	-	151	129	130	127	132	133	133	137	136	137	132	123	124	119	115	115
57	NPC 400 MW Sierra Solar BESS_26	-	-	227	194	195	190	199	199	200	205	205	205	198	184	185	178	172	173
58	**NVE.Proposed.solar.BESS Total**	-	-	378	323	325	317	331	332	333	342	341	342	330	307	309	297	287	288
59	**Proposed Total**	-	-	639	661	661	651	652	653	653	655	654	655	641	616	616	602	591	591

SECTION 9. FINANCIAL PLAN

A. Introduction

The following section summarizes the results of the analysis of financial impacts of the Preferred, Alternate and No Repower Plans presented in this IRP Amendment. The Financial Plan for both Nevada Power and Sierra spans a 20-year period (2022-2041) and analyzes these three scenarios from the perspective of customers and the Companies using several financial metrics as mandated by NAC § 704.9401(1). As discussed in the Economic Analysis Section, the No Repower Plan is being presented to address the requirement in Directive 4 in the Commission's June 12, 2023, Order in the Fourth Amendment for comprehensive analysis and comparisons of the financial and economic impacts of each potential complete solution of the Valmy coal plant. Also included in the Financial Plan, for both utilities, are descriptions of the financial forecasting assumptions and common methodologies used to prepare the Financial Plan. Further, in recognition of the Commission's requests in prior recent IRP amendment proceedings, the Companies are providing customer rate impact of the Preferred Plan as part of this Financial Plan.

B. Capital Expenditures

The capital expenditures and cash flow analysis prepared for the Financial Plan utilize the capital expense recovery ("CER") model (described in the Economic Analysis section above) for the Preferred, Alternate and No Repower Plans. Figure FP-1 below compares Nevada Power's total capital expenditures (including AFUDC) for the three Plans on a yearly basis over the planning period. Capital expenditures for the 20-year period, 2022-2041, are estimated to total $15.6 billion for the Preferred Plan, $15.9 billion for the Alternate Plan and $16.0 billion for the No Repower Plan for Nevada Power.[69] For Sierra, capital requirements shown in Figure FP-2 are estimated to total $10.7 billion for the Preferred Plan, $11.0 billion for the Alternate Plan and $11.1 billion for the No Repower Plan. Additional project details can be found in the Economic Analysis section.

For Nevada Power, the incremental capital expenditures requested in this filing occur in years 2024 through 2027 and are estimated to be $1.0 billion, $1.2 billion and $1.4 billion in the Preferred, Alternate and No Repower Plans, respectively. For Sierra, the incremental capital expenditures requested in this filing occur in years 2024 through 2030 and are estimated to be $0.9 billion, $1.0 billion and $1.2 billion for the Preferred, Alternate and No Repower Plans, respectively.

[69] As described in the Renewables Section, the Sierra Solar PV/BESS project costs included in the Financial Plan are higher than the values requested for approval in this filing. The Sierra Solar costs for the PV and BESS components were each overstated by about $25 million.in the Financial Plan.

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

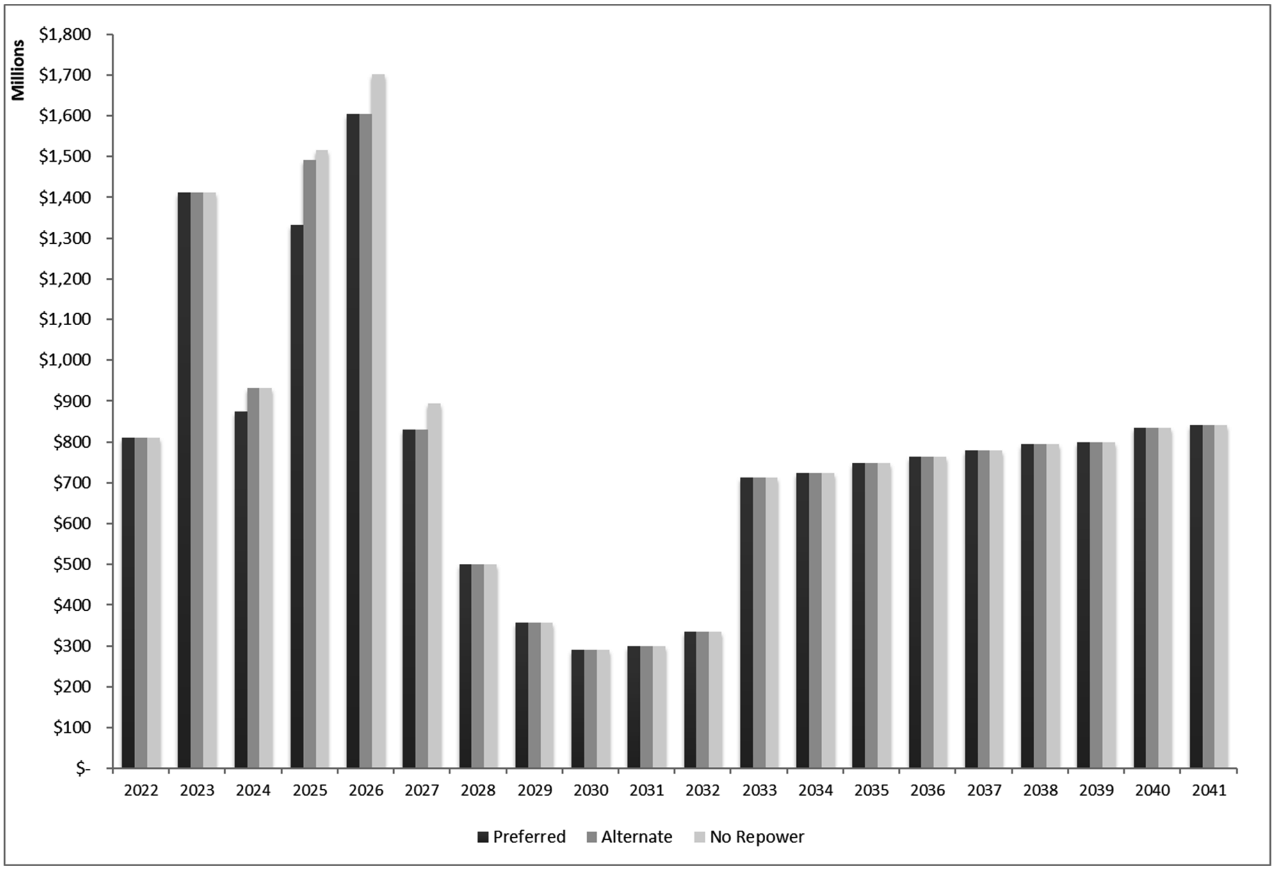
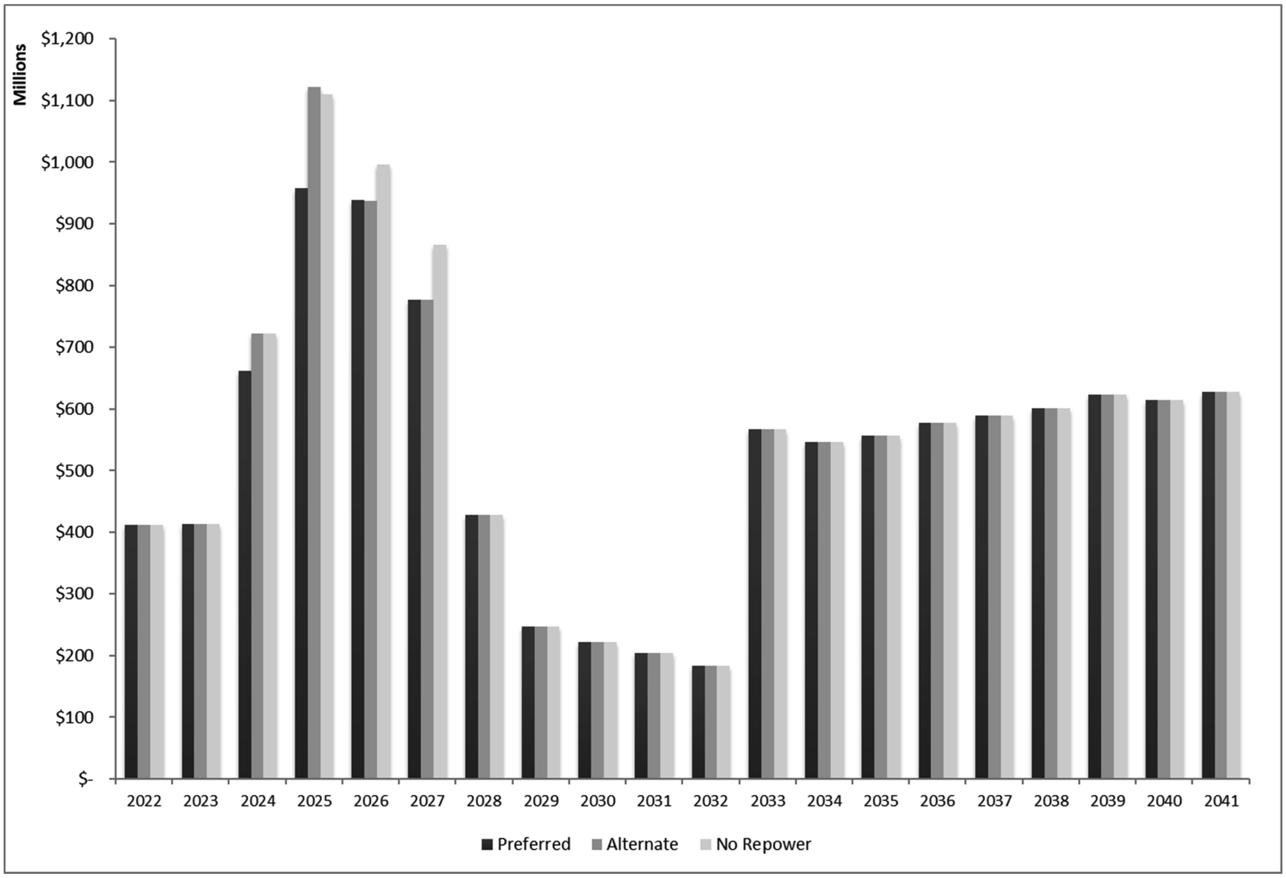


FIGURE FP-2
SIERRA
CAPITAL EXPENDITURES ($ - MILLIONS)
(Including AFUDC)



C. External Financing Requirements [REDACTED]

For the majority of the years during the 2022-2041 period, cash generated from operations at both utilities will be used to fund the capital projects costs set forth in the CERs for each of the Preferred, Alternate and No Repower Plans. Nevertheless, the Companies will have a continued need to access external short- and long-term financing to finance capital projects, working capital, refinance maturing debt, and maintain capital structures that are appropriate for their investment grade credit ratings. For Nevada Power, Figure FP-3 depicts annual total external debt requirements over the forecast horizon for the Preferred, Alternate and No Repower Plans. External financing requirements for the 20-year period are estimated to total [redacted], [redacted] and [redacted] for the Preferred, Alternate and No Repower Plans, respectively. 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 and No Repower Plans.

FIGURE FP-3
NEVADA POWER – [REDACTED]
SUMMARY OF EXTERNAL DEBT FINANCING($ - MILLIONS)

[redacted]

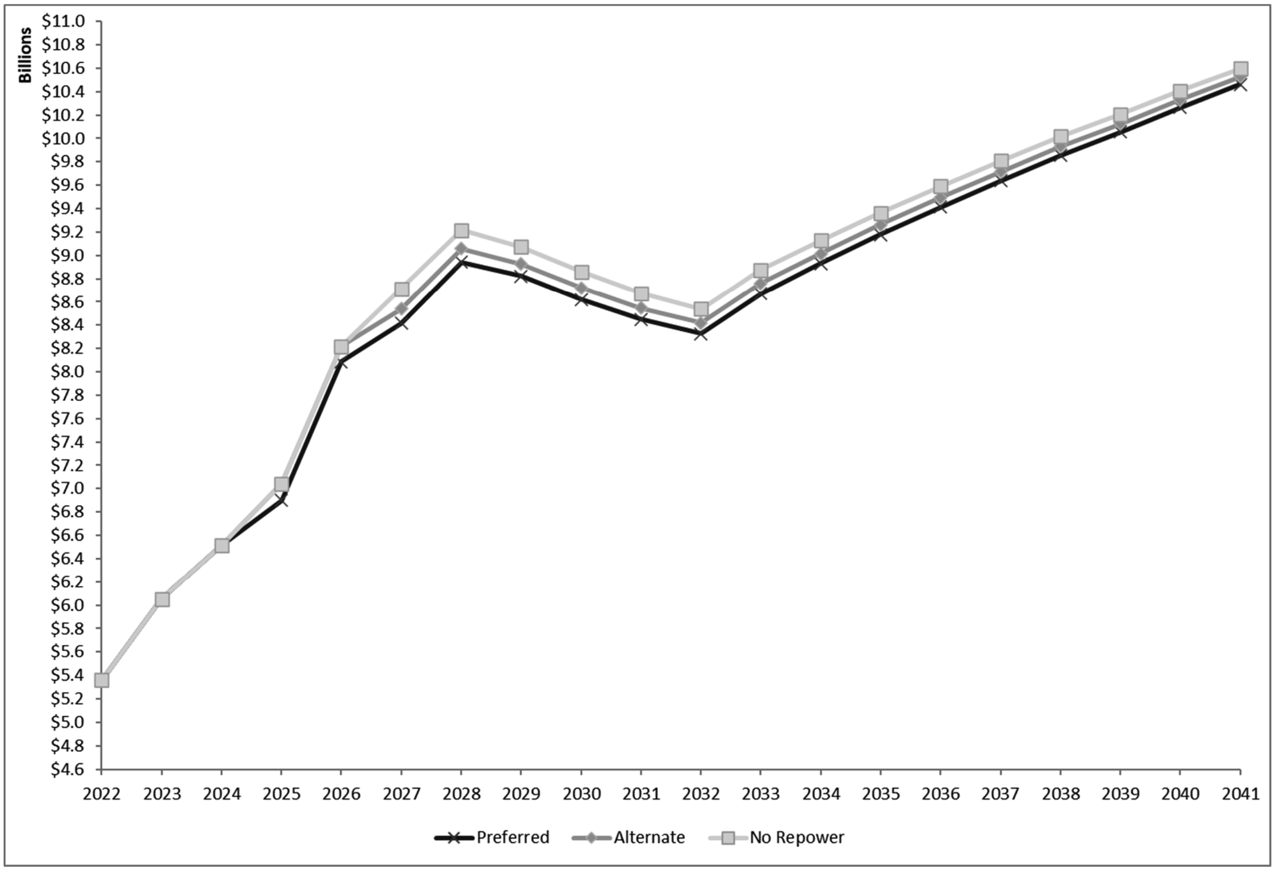
FIGURE FP-4
SIERRA – [REDACTED[SUMMARY OF EXTERNAL DEBT FINANCING
($ - MILLIONS)

[redacted]

D. Total Rate Base

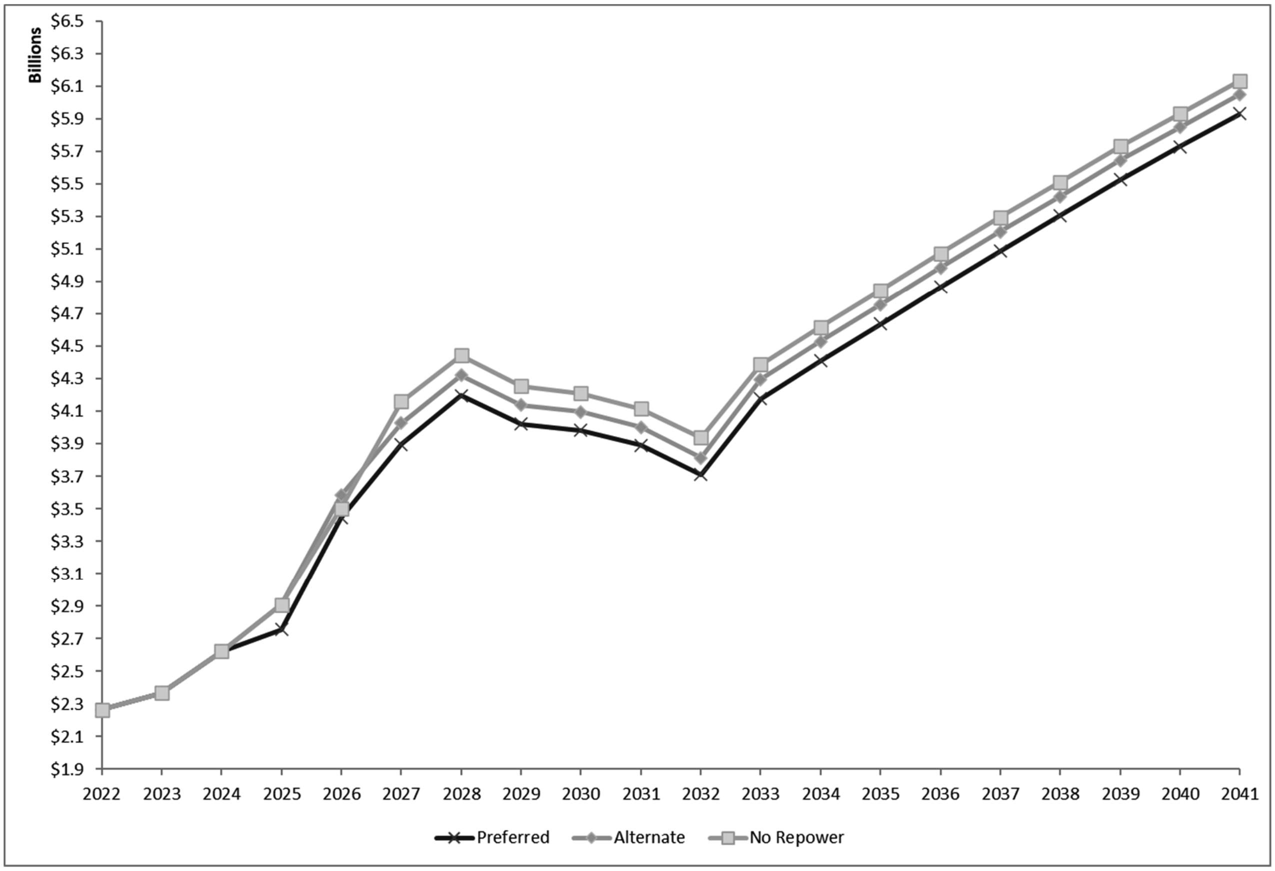
For Nevada Power, Figure FP-5 below compares total rate base per year over the planning period. Compound annual growth rates for rate base over the planning period total 3.4 percent for the Preferred and Alternate Plans and 3.5 percent for the No Repower Plan.

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



For Sierra, Figure FP-6 below compares total electric rate base per year over the 20-year planning period. Compound annual growth rates for rate base over the planning period total 4.9 percent for the Preferred Plan, 5.0 percent for the Alternate Plan and 5.1 percent for the No Repower Plan.

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

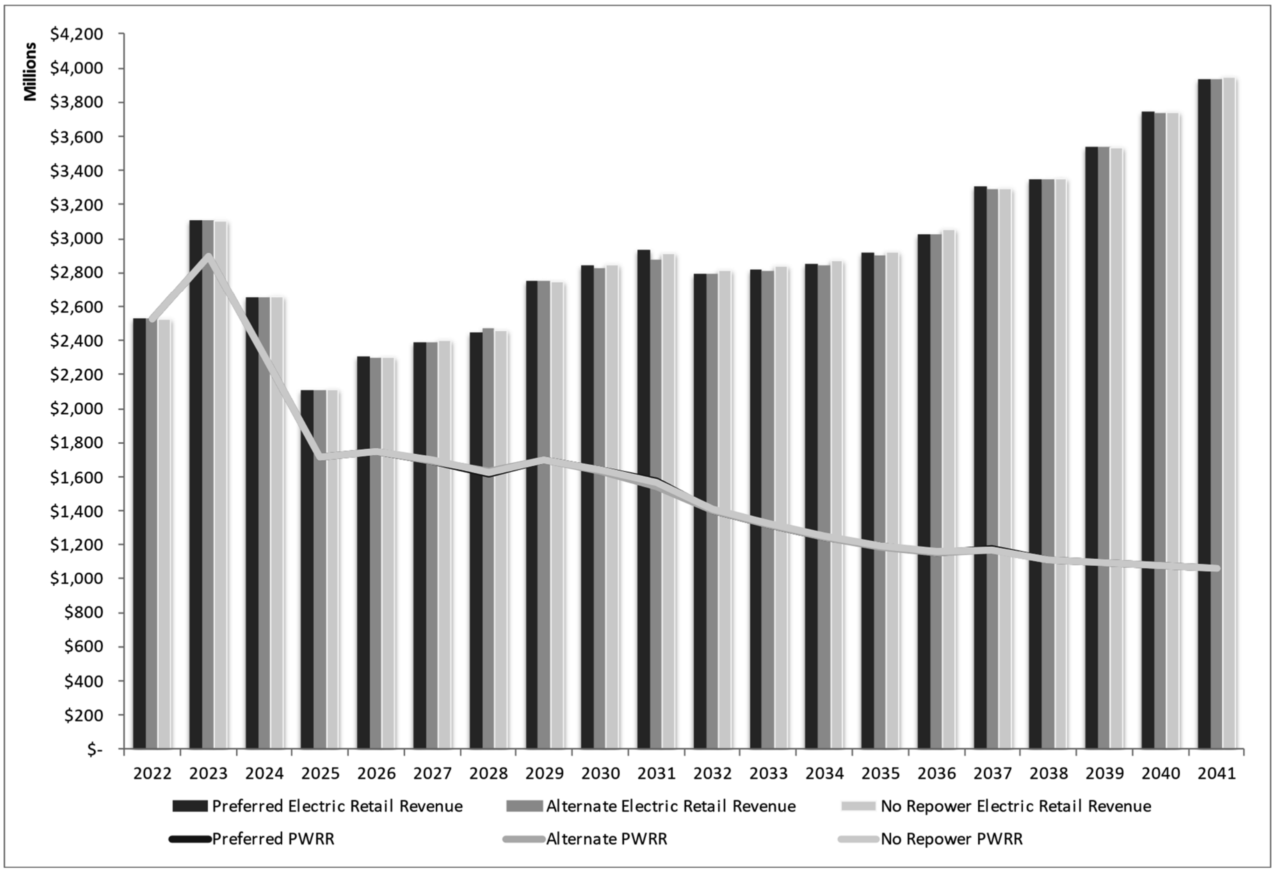


E. Electric Revenue

During the 20-year planning period, the Preferred and Alternate Plans for Nevada Power result in a compound annual growth rate in electric retail revenue (including fuel costs) of 2.2 percent (from approximately $2.5 billion to $3.9 billion). The No Repower Plan for Nevada Power results in a compound annual growth rate in electric retail revenue (including fuel costs) of 2.3 percent (from approximately $2.5 billion to $3.9 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.

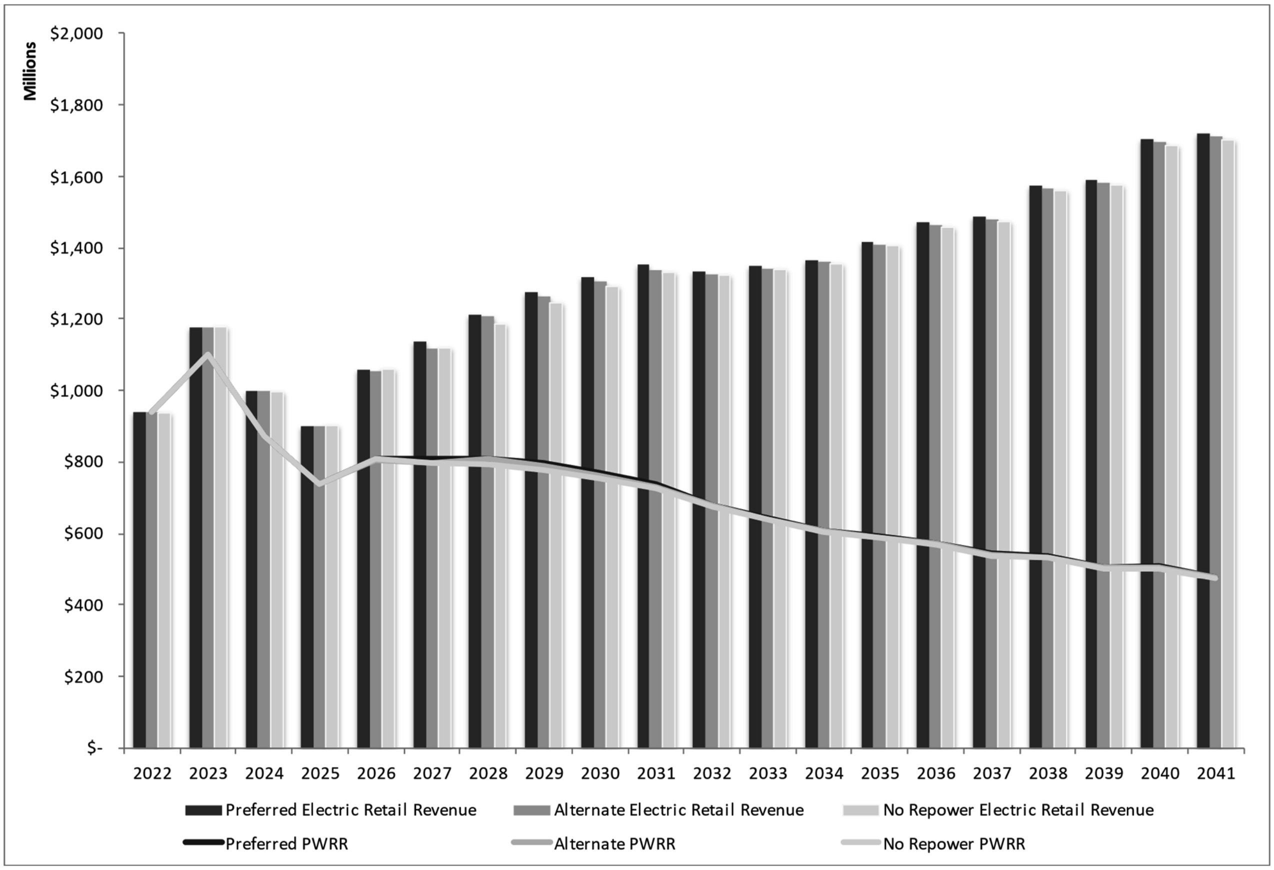
FIGURE FP-7

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 3.1 percent (from approximately $0.9 billion to $1.7 billion). The No Repower Plan results in a compound annual growth rate in electric retail revenue (including fuel costs) of 3.0 percent (from approximately $0.9 billion to $1.7 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)



It is important to note that the projected 2023-2024 revenues at both utilities are elevated due to the recovery of the Companies' deferred energy account adjustment ("DEAA") balances. According to current forecasts, the Companies' recovery of the under-recovered DEAA balances occurs largely by the end of 2024. These projections are based on normal load levels, and normal fuel and purchase power and natural gas prices. Increases in fuel and purchase power costs and natural gas costs may impact the recovery period.

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. Common Methodologies

The financial analysis was performed using the Companies' financial forecasting model based on the Utilities International, Inc. ("UI") platform. The model uses many of the same inputs (e.g., capital expenditures or "CAPEX," AFUDC rate based at the Companies' authorized rates of returns, production costs, depreciation rates and load forecast) from the CERs that are utilized in the Economic Analysis section described earlier. Additional inputs include pro-forma capital structures and capital costs. The UI platform simulates general rate review proceedings based on rate case timings that support major capital investments. The rate case timings used are summarized in the assumption section below.

2. Assumptions

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

- Sierra's next general rate increase/decrease will go into effect January 1, 2025.
- Nevada Power's next general rate increase/decrease will go into effect January 1, 2024.
- Rate case cycles occur at various frequencies scheduled to support major capital investments. The certification years for Nevada Power are 2025, 2026, 2028, 2031, 2034, 2036, 2038 2040 and 2042. The certification years for Sierra are 2024, 2025, 2027, 2028, 2031, 2034, 2035, 2037, 2039 and 2041.
- Inflation rate assumed over the forecast horizon was 2.3 percent.
- The AFUDC rate for new projects is set at the marginal cost of capital 7.14 percent for Nevada Power and 6.95 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 6.95 percent was used as the discount rate and was based on the currently authorized 9.50 percent ROE.[70]
- The assumed marginal cost of new long-term debt ranges between 4.71 percent and 6.10 percent based on current pricing information.

[70] For Nevada Power, the financial modeling used 53.3 percent equity ratio for 2024-2025 and 52.4 percent equity ratio for 2026 and beyond. Sierra equity ratio was 52.4 percent in 2024, 54.0 percent in 2025-2027 and 53.0 percent in 2028-2041.

- A 21 percent statutory federal income tax rate.
- Full recovery of all above-the-line costs incurred (including energy, operating and capital).

G. Financial Risks

This section discusses in more detail several financial matters which are important in assessing the Companies' Preferred, Alternate and No Repower Plans.

1. External Financing Costs

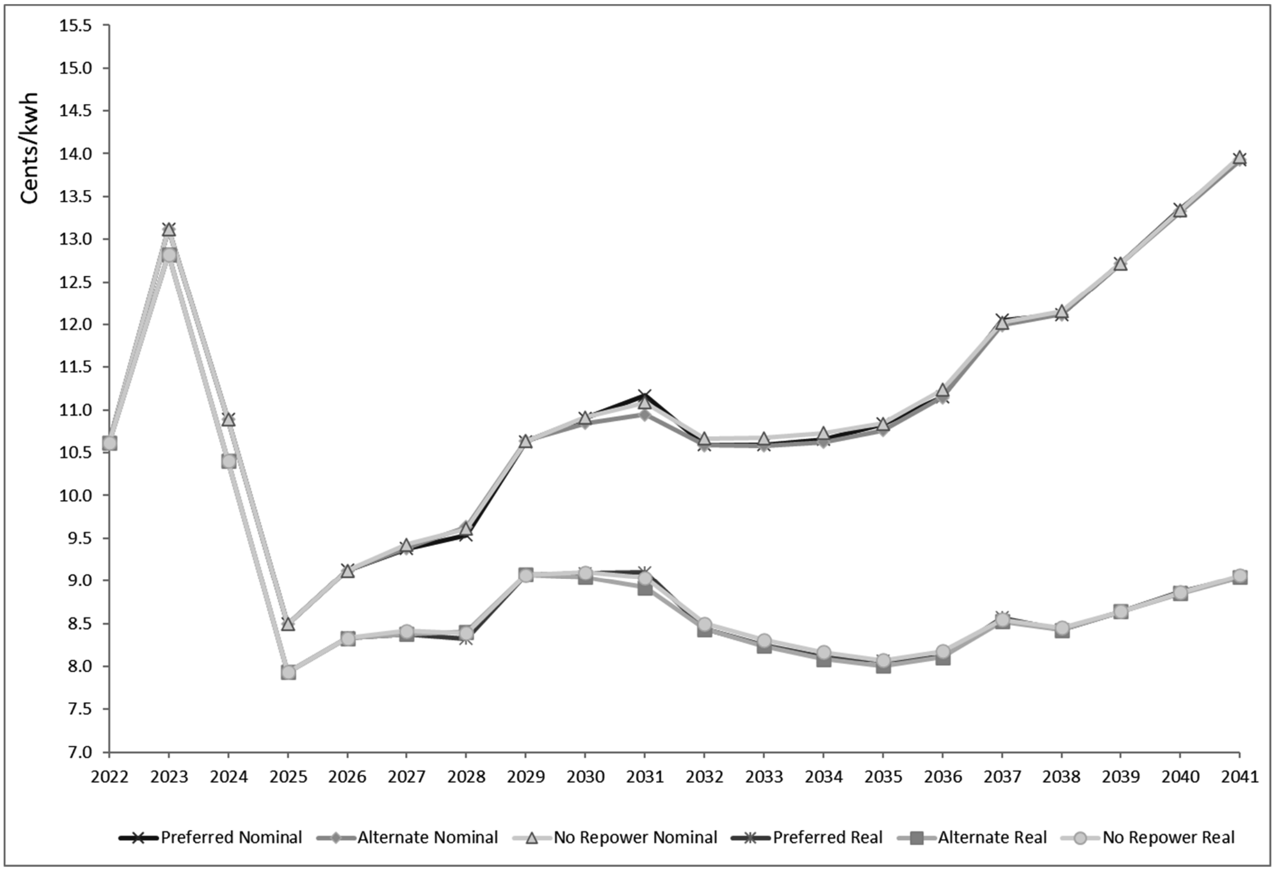
Due to the ongoing need to access external capital, the Companies must continue to rely on access to the financial markets. Increasing volatility in, and over-reliance on, financial markets could lead to excessive financing costs for customers in order to fund future investments on their behalf.

2. Impact on Average System Cost

As shown in the Figure FP-9, the nominal average system cost per kWh for Nevada Power under the Preferred Plan increases from 10.61 cents in 2022 to 13.93 cents in 2041, increases from 10.61 cents in 2022 to 13.93 cents in 2041 under the Alternate Plan, and increased from 10.61 cents in 2022 to 13.96 cents in 2041 under No Repower Plan. The compound annual growth rate for the nominal average system cost over the forecast period is 1.4 percent for the Preferred, Alternate and No Repower Plans. Average system costs are projected to increase over the 20 years on a nominal basis, but, when inflation is reflected, then the average system costs are forecasted to decrease slightly on a real basis. The compound annual growth rate for real average system costs are (0.8) percent for the Preferred, Alternate and No Repower Plans.

FIGURE FP-9

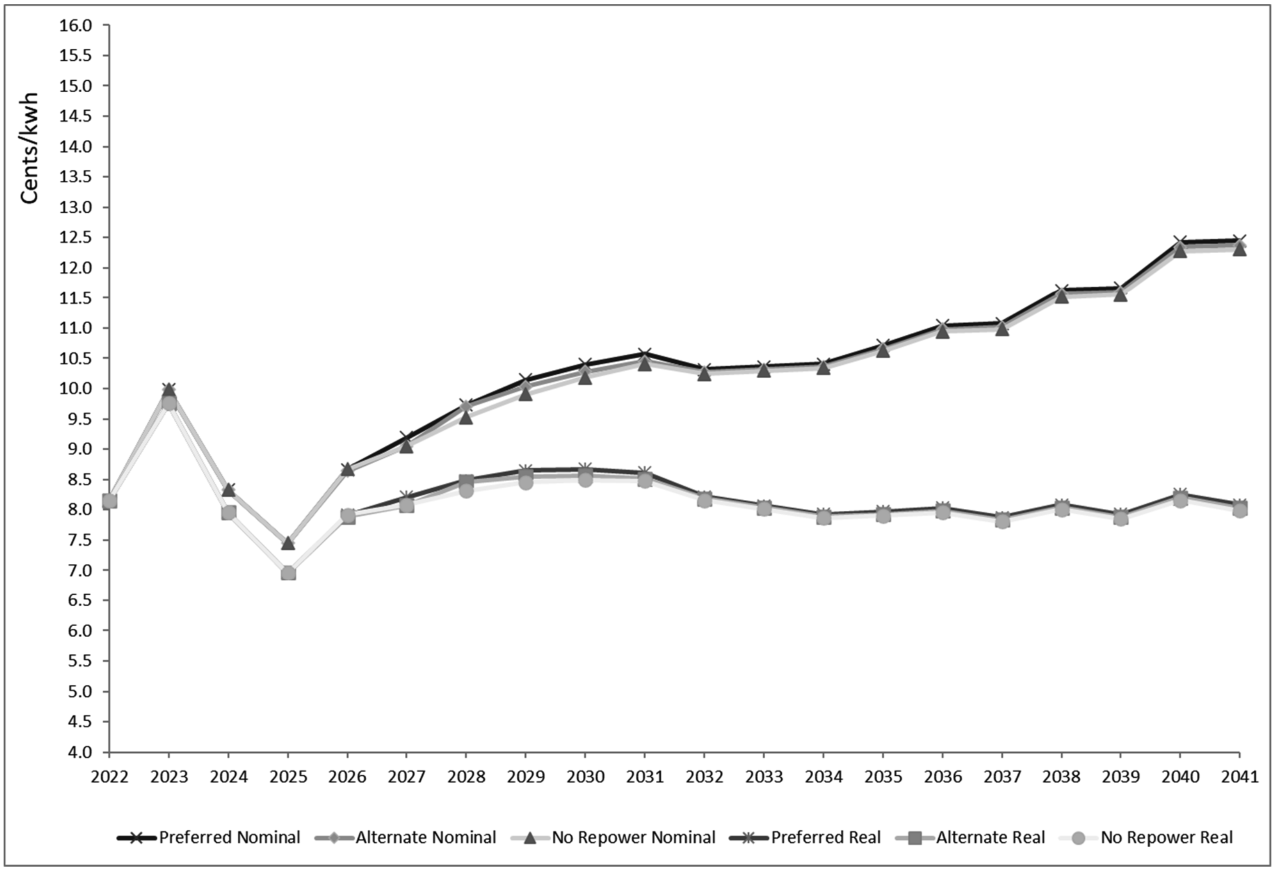
**NEVADA POWER
NOMINAL & REAL AVERAGE SYSTEM COST (CENTS/KWH)**



For Sierra, Figure FP-10 illustrates that the nominal average system cost per kWh is projected to increase over the 20 years from 8.15 cents in 2022 to 12.45 cents in 2041 under the Preferred Plan, from 8.15 cents in 2022 to 12.37 cents in 2041 under the Alternate Plan, and from 8.15 cents in 2022 to 12.30 cents in 2041 under No Repower Plan. The compound annual growth rate for the nominal average system cost over the forecast period is 2.1 percent for the Preferred, Alternate and No Repower Plans. The real average system costs for Sierra have a compound annual growth rate of 0.0 percent for the Preferred Plan and (0.1) percent for the Alternate and No Repower 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 rates comparable to those experienced by similarly rated utilities. Annual projected credit metrics for Nevada Power are shown in Figures FP-11 through FP-14 and Sierra's are illustrated in Figures FP-15 through FP-18. These credit metrics do not reflect adjustments that the rating agencies will make for off balance sheet obligations.

Figures FP-14 and FP-18 summarize the cash generated from operations relative to capital expenditures for Nevada Power and Sierra, respectively. For Nevada Power, cash generated from operations exceeds capital expenditures for most of the annual periods in the Preferred, Alternate and No Repower Plans. For Sierra, cash generated from operational funds may not always exceed capital expenditures periods in the Preferred, Alternate and No Repower Plans but over the 20-year period it operates at a level that is close and the Company believes it will be able to continually maintain credit quality. Despite the ability to fund a large portion of capital expenditures with internally generated cash, Figures FP-3 and FP-4 clearly illustrate the Companies' ongoing need to access external debt capital as the Companies maintain a balanced debt and equity level. There will be some pressure on Sierra credit metrics during the heightened level of debt issuances as Sierra works to lower equity to the approved level in the latest general rate case and therefore, and as always, it will be important to maintain investment grade credit metrics. Since some of the graphs do illustrate years of weakening metrics, it is important to note these metrics are calculated using standard methodologies which may not be the same as those used by Moody's and Standard & Poor's. The Companies will continually manage their capital structures in a way that does its best to minimize any potential negative pressure on credit quality, but regulatory support remains an important factor in the credit ratings process.

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

[redacted]

FIGURE FP-12
NEVADA POWER
(REDACTED) EBITDA[71] INTEREST COVERAGE

[redacted]

[71] EBITDA stands for earnings before interest, taxes, depreciation and amortization.

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

[redacted]

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

[redacted]

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

[redacted]

FIGURE FP-16
SIERRA
(REDACTED) EBITDA INTEREST COVERAGE

[redacted]

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

[redacted]

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

[redacted]

H. Customer Rate Impact

The Base Tariff General Rate ("BTGR") rate impact analysis for the Preferred Plan is shown in Table FP-I. The table does not demonstrate a cost increase to customers but a BTGR rate impact. This Amendment contains projects meant to address resource adequacy and reduce the Companies' reliance on market purchases. With reductions in market purchases, the Companies should see comparatively lower power purchase costs and, therefore, lower pass-through customer energy costs.

NV Energy calculated the BTGR rate impact of the projects being proposed in this 5th IRP Amendment using the methodology employed in Table Hopps-Direct-1 in Docket No. 22-09006, which provides the average cost in dollars per kWh rate impact for each rate class through 2032. The Companies calculated the average cost to customers, in dollars per year, with and without the 5th IRP Amendment projects to find the incremental average BTGR cost to customers. The calculated incremental average cost to customers was then applied to the various rate classes, as it has been done in previous dockets, using the modeled pro-rata split based on current rate design. These per customer class rate impacts were applied to the load forecast, in kWh, from the instant docket to produce the per kWh rate impact.

The analysis shows maximum annual nominal rate impact of approximately \$0.0059 at Nevada Power per kWh (\$0.0051 per kWh when adjusted for inflation) and \$0.0134 per kWh at Sierra (\$0.0119 per kWh when adjusted for inflation) for residential customers in both utilities and smaller impacts for all but one other customer classes.

TABLE FP-1
CUSTOMER RATE (BTGR) IMPACT OF THE PROPOSED 5TH AMENDMENT TO THE 2021 INTEGRATED RESOURCE PLAN

Average System Cost by Customer Class **Dollars per kWh (Nominal)**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Nevada Power Company										
Residential	-	-	-	(0.0000)	0.0004	0.0004	0.0059	0.0059	0.0059	0.0037
Small Commercial	-	-	-	(0.0000)	0.0002	0.0002	0.0035	0.0035	0.0035	0.0022
Industrial	-	-	-	(0.0000)	0.0002	0.0002	0.0025	0.0024	0.0024	0.0015
Public Streets & Highway Lighting	-	-	-	(0.0000)	0.0001	0.0001	0.0007	0.0007	0.0007	0.0005
Sales to Public Authority	-	-	-	(0.0000)	0.0001	0.0001	0.0011	0.0011	0.0011	0.0007
Distribution Only	-	-	-	(0.0000)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sierra Pacific Power Company										
Residential	-	-	(0.0000)	(0.0000)	(0.0000)	0.0134	0.0120	0.0120	0.0121	0.0084
Small Commercial	-	-	(0.0000)	(0.0000)	(0.0000)	0.0082	0.0074	0.0074	0.0074	0.0052
Industrial	-	-	(0.0000)	(0.0000)	(0.0000)	0.0057	0.0052	0.0052	0.0051	0.0037
Public Streets & Highway Lighting	-	-	(0.0000)	(0.0000)	(0.0000)	0.0697	0.0625	0.0614	0.0603	0.0442
Distribution Only	-	-	(0.0000)	(0.0000)	(0.0000)	0.0001	0.0000	0.0000	0.0000	0.0000

GDP Deflator 1.023

	0	1	2	3	4	5	6	7	8	9
Average System Cost by Customer Class **Dollars per kWh (Real)**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Nevada Power Company										
Residential	-	-	-	(0.0000)	0.0004	0.0004	0.0051	0.0050	0.0049	0.0030
Small Commercial	-	-	-	(0.0000)	0.0002	0.0002	0.0030	0.0030	0.0029	0.0018
Industrial	-	-	-	(0.0000)	0.0002	0.0002	0.0021	0.0021	0.0020	0.0013
Public Streets & Highway Lighting	-	-	-	(0.0000)	0.0000	0.0000	0.0006	0.0006	0.0006	0.0004
Sales to Public Authority	-	-	-	(0.0000)	0.0001	0.0001	0.0009	0.0009	0.0009	0.0006
Distribution Only	-	-	-	(0.0000)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Sierra Pacific Power Company										
Residential	-	-	(0.0000)	(0.0000)	(0.0000)	0.0119	0.0104	0.0103	0.0101	0.0069
Small Commercial	-	-	(0.0000)	(0.0000)	(0.0000)	0.0073	0.0064	0.0063	0.0061	0.0043
Industrial	-	-	(0.0000)	(0.0000)	(0.0000)	0.0051	0.0046	0.0044	0.0043	0.0030
Public Streets & Highway Lighting	-	-	(0.0000)	(0.0000)	(0.0000)	0.0622	0.0546	0.0523	0.0502	0.0360
Distribution Only	-	-	(0.0000)	(0.0000)	(0.0000)	0.0000	0.0000	0.0000	0.0000	0.0000

I. Conclusion

It is important to note the primary driver of the capital proposed in this filing is for resource adequacy needs, but it is always important to also understand the financial impacts. As we evaluate the financial results of the modeling for the Preferred, Alternate or No Repower Plans, the Companies has the capacity and can afford either of these plans. The amount of capital in the Companies' Preferred, Alternate and No Repower Plans will add some pressure on credit metrics for a couple years during construction, but it is the Companies' position that they will be able to maintain financial strength while over the years building stronger financial strength when the assets are in rates and by taking advantage of available tax credits helps minimize the costs to customers. The Companies have the financial ability and capacity to complete the projects in this filing.

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 Fifth 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 Fifth Amendment to their 2021 Joint Integrated Resource Plan. Among the requests stated in the Joint Application, the Companies are seeking: (1) to convert the existing coal fueled plant at the North Valmy Generating Station to a cleaner natural gas fueled plant and continue its operation through 2049; (2) to purchase, install, and operate a company-owned 400 megawatt ("MW") Sierra Solar PV plant along with a 400 MW, four-hour battery storage system in Northern Nevada along with associated transmission infrastructure; (3) to continue operation of Tracy units 4 and 5 to 2049; (4) to purchase development assets for the 149 MW PV and 149 MW BESS Crescent Valley Solar project; (5) to construct the Esmeralda and Amargosa substations transformers; and (6) to construct the necessary infrastructure in the Apex Area Master Plan.**

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

[1] NRS 704.069 states in pertinent part:

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. 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.

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing **JOINT APPLICATION FOR APPROVAL OF THE FIFTH AMENDMENT TO THE 2021 JOINT INTEGRATED RESOURCE PLAN OF NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A/ NV ENERGY** in Docket No. 23-08___ upon the persons listed below by electronic mail:

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DATED this 21st day of August, 2023.

/s/Ashleigh Sternod
Ashleigh Sternod
Regulatory Operations Analyst
Nevada Power Company
Sierra Pacific Power Company