BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval of the Third Amendment to the 2018 Joint Integrated Resource Plan, including a request for approval of three new renewable energy power purchase agreements, and updates to the Transmission Action Plan including several new projects needed to allow the new renewable facilities to interconnect into the system, and to meet distribution load growth.	Docket No. 19-06___

VOLUME 1 OF 5

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

TRANSMITTAL LETTER

June 24, 2019

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. 19-06___ - 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 Third Amendment to the 2018 Joint IRP.

Dear Ms. Osborne:

Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (the "Companies") hereby submit for approval their Third Amendment to the 2018 Joint Integrated Resource Plan (approved by the Commission on February 15, 2019, in Docket No. 18-06003). This Third Amendment requests to update and modify the renewable portion of the Supply-Side Action Plan and the Transmission Action Plan.

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

- **Application Exhibit A** is a narrative discussion of the all eligible load forecast and updates to the Supply-Side Action Plan and the Transmission Action Plan.

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

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

In addition, the Application is supported by Technical Appendices and prepared direct testimony.

- **John (Jack) P. McGinley**
- **Terry Baxter**
- **Dr. David Harrison**
- **Shane Pritchard**
- **Marc Reyes**
- **Sachin Verma**

None of the information set forth in the Prepared Direct Testimony is commercially confidential and/or trade secret information subject to protection pursuant to NRS § 703.190.

However, Technical Appendices GEN-1, ECON-2, REN-3, REN-7, REN-8, and REN-9 contain confidential, proprietary, and/or trade secret information protected by NRS 703.190. GEN-1 contains the Companies' generation unit characteristics data, including heat rates and other sensitive technical characteristics. ECON-2 supplies sensitive projected capital cost information related to conventional placeholder resources. REN-3 covers the Companies' generic renewable placeholder pricing information. REN-7 through REN-9, which respectively are 2018 Fall RFP final shortlist scoring report, final due diligence and selection reports, and report of the Independent Evaluator contain sensitive third-party information, including detailed bid information as well as an assessment of the Companies' selection of the initial and final shortlists.

These Technical Appendices contain commercially sensitive and/or trade secret information that derive independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets and its future procurement opportunities. This information is not known outside the Companies and its distribution is limited within the Companies. Releasing this highly sensitive information would disadvantage the Companies and their customers by limiting their ability to foster competition among prospective suppliers; compromising the Companies' negotiating position and reducing bargaining leverage. Publication of this information would unfairly advantage competing suppliers and impair the Companies' ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers.

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

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

Should you have any questions regarding this filing, please contact me at 775-834-5692 or mgreene@nvenergy.com.

Sincerely,

/s/ Michael Greene
Michael Greene
Deputy General Counsel

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

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REN-6-MS (a)	Long-Term RPP Agreement with Arrow Canyon Solar
REN-6-MS (b)	Moapa Solar RPS Regulation Roadmap
REN-6-SBS (a)	Long-Term RPP Agreement with 300MS 8me, LLC
REN-6-SBS (b)	Southern Bighorn Solar RPS Regulation Roadmap

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ITEM	DESCRIPTION
REN-7	RFP Final Shortlist Scoring Report (Confidential)
REN-8	Final Due Diligence and Selection Reports (Confidential)
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TRAN-1	Company 79-119 - Moapa Solar LGIA
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TRAN-3	Company 151 – Apex Solar LGIA
TRAN-4	Gemini Solar – NTP System Impact Study

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **NEVADA POWER COMPANY D/B/A NV ENERGY and SIERRA PACIFIC POWER COMPANY D/B/A/ NV ENERGY** Docket No. 19-06___ upon the persons listed below by the following:

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DATED this 24th day of June, 2019.

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

APPLICATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval of the Third Amendment to the 2018 Joint Integrated Resource Plan, including a request for approval of three new renewable energy power purchase agreements, and updates to the Transmission Action Plan, including several new projects needed to allow the new renewable facilities to interconnect into the system, to meet distribution load growth, and to increase reliability.	)	Docket No. 19-06___

APPLICATION TO APPROVE THIRD AMENDMENT TO 2018 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 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' Third Amendment to their 2018 joint triennial integrated resource plan ("2018 Joint IRP"). As an amendment to the Companies' 2018 Joint IRP, NRS § 704.751(2)(a) requires that that Commission issue an order accepting or modifying the Third 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 December 6, 2019.

I.
SUMMARY AND INTRODUCTION

Since the filing of the 2018 Joint IRP, the Companies issued a renewable energy request for proposals ("RE RFP") seeking additional renewable resources to expand their supply-side portfolios. In addition, the 80th session of the Nevada Legislature adopted Senate Bill 358 that will increase the renewable portfolio standard ("RPS") to 50 percent by 2030. These and related events have raised the need to amend some aspects of the Action Plan approved by the Commission in Docket No. 18-06003.

Included in this Third Amendment are requests for approval of three new renewable energy power purchase agreements ("PPAs") and to make several updates and additions to the Companies' Transmission Plan. In addition, the Companies have included a load forecast, for informational purposes that shows the impact if all eligible customers under NRS Chapter 704B transitioned to distribution-only service ("DOS").

The PPAs for which approvals are sought in this Third Amendment result in material changes to the Companies' loads and resources tables (as both capacity and energy additions) and have been analyzed utilizing production cost modeling. Thus, consistent with NAC § 704.9516(1), which sets forth the requirements of an amendment to an approved Action Plan, an updated current peak demand forecast and a current loads and resources table are provided. The projects addressed in this Third Amendment have not had an incremental impact on the Companies' ability to finance their operations or on imputed debt.

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:

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Reno, NV 89511
775-834-5692
mgreene@nvenergy.com

LoreLei Reid
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 Third Amendment, the Companies have included with this Application and incorporated herein by reference the following exhibits:

- **Application Exhibit A** is a narrative discussion of the load forecast, the renewable portion of the Supply-Side Action Plan, and the Transmission Action Plan.
- **Application Exhibit B** is a proposed notice of the Application as required by NAC § 703.162.
- **Application Exhibit C** is an updated loads and resources table.

The form of Exhibit A, the Narrative, was selected because it is the form used in IRPs and IRP amendments to provide the Commission and stakeholders with detailed and technical information regarding the inputs, in-depth descriptions of the analytical techniques applied to the questions to be answered in IRP filings, as well as clear communication of the results of integrated resource plan 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 Third 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. A summary of this information, is set forth by general topic below.

John (Jack) P. McGinley is the executive sponsor of the Third Amendment.

The informational load forecast that shows the impact if all eligible customers under NRS Chapter 704B transitioned to DOS is addressed in Section 3 of the Narrative, and supported by the prepared direct testimony of **Terry Baxter**.

The updated portion of the Supply-Side Action Plan addressing the three new renewable PPAs is discussed in Section 4 of the Narrative, in Technical Appendices REN-1 through REN-9, and in the prepared direct testimony of **Shane Pritchard**. Mr. Pritchard supports both near-term outlook and long-term planning to meet Nevada's RPS. He also sponsors and supports the processes followed and results of the RE RFP, including the request for approval of three PPAs for 1,190 MW of new renewable resources.

Transmission Action Plan additions of a new transmission project required to meet growth and reliability needs as well as Transmission Action Plan additions for network upgrades needed to satisfy three new generator interconnection requests are discussed in Section 6 of the narrative, Technical Appendices TRAN-1 through TRAN-4, and the prepared direct testimony of **Sachin Verma**.

The Economic Analysis narrative follows the Supply-Side narrative and discusses the methodologies and analytical tools used to perform the integrated economic analysis that underlies the Companies' requests for approvals in this Third Amendment. This section also describes the calculation of environmental externalities for the Third Amendment. The economic analysis narrative and Technical Appendices ECON-1 through ECON-5 are sponsored in the prepared direct testimony of **Marc D. Reyes,** as well as **Dr. David Harrison, Jr.**, economist and Senior Vice President at NERA Economic Consulting. Dr. Harrison sponsors the discussion and analysis of environmental externalities contained in the Economic Analysis discussion, as well as Technical Appendix item ECON-6.

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

V.
CONFIDENTIALITY

None of the information set forth in the Prepared Direct Testimony is commercially confidential and/or trade secret information subject to protection pursuant to NRS § 703.190. However, Technical Appendices GEN-1, ECON-2, REN-3, REN-7, REN-8, and REN-9 contain confidential, proprietary, and/or trade secret information protected by NRS 703.190. GEN-1 contains the Companies' generation unit characteristics data, including heat rates and other sensitive technical characteristics. ECON-2 supplies sensitive capital projects information. REN-3 covers the Companies' generic renewable placeholder pricing information. REN-7 through REN-9, which respectively are 2018 Fall RFP final shortlist scoring report, final due diligence and selection reports, and report of the Independent Evaluator contain sensitive third-party information, including detailed bid information as well as an assessment of the Companies' selection of the initial and final shortlists.

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

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

VI.
PRAYER

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

1. Approval of the Companies' request to amend their 2019-2021 Supply-Side Action Plan to enter into the following three new renewable PPAs:

a. Nevada Power's PPA with Southern Bighorn Solar Farm for 300 MW (nameplate, AC) of solar PV generation, with an additional 135 MW capacity of co-located battery storage. Commercial operation is expected by September 1, 2023:

b. Nevada Power's PPA with Moapa Solar for 200 MW (nameplate, AC) of solar PV generation, with an additional 75 MW capacity of co-located battery storage. Commercial operation is expected by December 1, 2022; and

c. Nevada Power's PPA with Gemini Solar for 690 MW (nameplate, AC) of solar PV generation, with an additional 380 MW capacity of co-located battery storage. Commercial operation is expected by December 1, 2023.

2. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $1.3 million to construct network upgrades needed to support the interconnection of the Moapa Solar project at the Harry Allen Substation;

3. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $3.67 million to construct network upgrades needed to interconnect the Southern Bighorn Solar project at the Reid Gardner Substation;.

4. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $15.63 million to construct network upgrades needed to support the interconnection of Gemini Solar project at the new Crystal Substation;

5. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $13.42 million to construct a new 230 kV substation at the Apex Industrial Park to serve new load, and accommodate additional transmission interconnections and distribution transformers;

6. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $6.20 million to add three 230 kV breakers at the existing

Machacek substation, to provide increased customer reliability and address a potential safety hazard at the substation.

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

8. Grant any other requests as are specifically set forth in the testimony and exhibits filed herewith; and

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

Dated this 24th day of June, 2019.

Respectfully submitted,

NEVADA POWER COMPANY
SIERRA PACIFIC POWER COMPANY

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

APPLICATION EXHIBIT A

THIRD AMENDMENT TO
2018 JOINT INTEGRATED RESOURCE PLAN

NARRATIVE

Contents

SECTION 1. INTRODUCTION

Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra," and together with Nevada Power, the "Companies" or "NV Energy") are filing this Third Amendment to their 2018 joint integrated resource plan ("2018 Joint IRP").

This filing represents another step in the continued evolution of Nevada's energy industry and market. NV Energy, Inc.'s operating subsidiaries – Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a ("Sierra" and, together with Nevada Power, either the "Companies" or "NV Energy") – jointly make this integrated resource plan amendment (the "Amendment"). The Amendment seeks approval of long-term power purchase agreements between the Nevada Power and the developers of three new solar photovoltaic generating facilities, each with integrated battery storage systems.

The Amendment requests approval contracts for the energy produced by 1,190 megawatts ("MW") of solar photovoltaic generation units. The Amendment also request approval of 590 MW of battery storage. Together, these three projects represent an investment of approximately $3.86 billion dollars in Nevada's emerging clean energy economy. The projects are expected to yield a permanent, long-term increase in the workforce of 40 positions, with annual salaries in excess of $79,000. Total payroll associated with the projects is expected to exceed $100 million over the lives of the projects. The Amendment directly advances Nevada's energy policies. The Amendment brings forward new renewable energy projects that produce economic, health and environmental benefits for Nevadans.

The Amendment also solidifies the foundation upon which safe, reliable, reasonably priced electric service can be delivered to NV Energy's customers. The Amendment is not driven by a single planning need. In the evolving energy market, resource planning decisions are not binary. Renewable resources, for instance, are not added solely for the purpose of meeting a renewable portfolio standard. Instead, the renewable resources included in this Amendment position the Companies not only to meet the increases in the renewable portfolio standard established by Senate Bill 358, ***but also*** to meet the needs of a diverse group of stakeholders and policy objectives. More specifically, the supply-side plan:

1. Better positions NV Energy to meet the goal established by Nevada's energy policy makers (i.e., "Become a leading producer and consumer of clean and renewable energy, with a goal of achieving by 2050 an amount of energy production from zero carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in this State");[1]
2. Provides lower cost energy and capacity than market purchases, providing more price stability for NV Energy's customers;
3. With respect to economics, compares favorably to more "conventional" supply-side plan, with the levelized cost of energy produced by the three projects ranging between $36.86 per MWh and $42.83 per MWh, while the mean levelized cost of energy for a new gas combined-cycle generating facility is estimated to be $58 per MWh;[2]

[1] Senate Bill 358, 2019 Session of Nevada Legislature, §8(2).
[2] See, e.g., Lazard's Levelized Cost of Energy Analysis, Version 12.0 at 7 (November 2018)

4. Enables NV Energy to meet the demands made by large commercial and industrial customers for optional pricing programs that allow the customers to remain competitive in local, regional, national and international markets;
5. Allows NV Energy to return to long-term resource planning by relying less on short-term market energy purchases to reduce open capacity positions and, instead, use long-term commitments to ensure the Companies can meet the needs of Nevada's growing economy.

1. The failure of Question 3, coupled with customer retention efforts, provides the certainty necessary to make sound term resource planning decisions.

The Question 3 measure created uncertainty, complicating the integrated resource planning process. Because Question 3 prohibited "exclusive" generation franchises, stakeholders anticipated that NV Energy would sell its generating resources and transfer its long-term generating contracts if Question 3 passed. Supply side decisions necessarily were viewed through a short-run lens, rather than a long-run lens. Internally, NV Energy evaluating generation capital projects with a strict "break-even" guidepost: if project benefits did not outweigh projects costs before the retail competition would begin, the project was not pursued.

Similarly, the Commission shifted to short-run analysis. In July 2016, Nevada Power and Sierra sought permission to acquire the South Point Energy Center, a 504 MW combined-cycle generating facility located near Bullhead City, Arizona. The acquisition of South Point Energy Center (coupled with the addition of 100 MW of solar generation) was the least cost supply-side plan analyzed by the Companies. The Commission approved the addition of solar generation but rejected the acquisition of South Point Energy Center and directed the Companies to view resource planning through a short-run lens:

> 106. In response to voters' overwhelming support for the Energy Choice Initiative and the move toward a competitive market place for energy, the Commission denies [Nevada Power's] request to acquire South Point [Energy Center] via the [asset purchase agreement] between [Nevada Power] and South Point Energy Center, LLC dated April 1, 2016, and the 30-percent transfer of South Point [Energy Center] to [Sierra] by January 1, 2018.
>
> 107. The Commission finds that resource planning will not pause and [NV Energy] remains responsible for meeting the resource needs of its customers. Until there is greater certainty regarding the implementation of the Energy Choice Initiative and how many exit applications will be approved, resources to cover the open positions of [the Companies'] customers ***shall be short-term in nature*** (less than five years) and consistent with the energy policies of the State.[3]

In June 2018, the Companies brought forward the results of its January 9, 2018 request for renewable energy proposals. The results demonstrated that renewable energy projects had reached cost parity with conventional generating resource. When it became apparent later in the year that

[3] Order, Docket No. 16-07001, 16-07007 & 16-08027, ¶¶ 106 & 107 (iss. Feb. 16, 2017).

voters would not approve Question 3 a second time, NV Energy issued another request for renewable energy proposals. The results of that request for proposals provide the foundation for this filing and, once again, demonstrate that renewable energy resources coupled with integrated battery storage projects are economically efficient options for customers. Moreover, the failure of Question 3 to meet voter approval provides the needed certainty to view resource planning decisions through a long-run lens.[4]

In this vein, this Amendment looks to long-term commitments – new renewable power purchase agreements with firm capacity provided by battery storage products – to reduce the Companies' open position. The three projects with integrated battery storage provide 802 MW of capacity (238 MW related to solar photovoltaic generation and 564 MW associated solely with battery storage), or the equivalent of 1.6 times the capacity provided by South Point Energy Center.[5]

2. The Amendment positions Nevada to be a leading producer and consumer of renewable energy.

Energy markets are evolving. Across the country, stakeholders – i.e., policy makers, customers and advocacy organizations – are pressing electric service providers to reduce carbon emissions and increase the use of renewable energy. Nevada is no exception. The 80th Nevada Legislature passed, and Governor Sisolak signed legislation consistent with this nationwide trend. Senate Bill 358 increases Nevada's renewable portfolio standard, reaching 50 percent in 2030. In addition, the legislation provides:

> Sec. 8. The Legislature finds and declares that it is the policy of this State to:
> 1. Encourage and accelerate the development of new renewable energy projects for the economic, health and environmental benefits provided to the people of this State;
> 2. Become a leading producer and consumer of clean and renewable energy, with a goal of achieving by 2050 an amount of energy production from zero carbon dioxide emission resources equal to the total amount of electricity sold by providers of electric service in this State; and
> 3. Ensure that the benefits of the increased use of portfolio energy systems and energy efficiency measures are received by the residents of this State. Such benefits include, without limitation, improved air quality, reduced water use, a more diverse portfolio of resources for generating electricity, reduced fossil fuel consumption and more stable rates for retail customers of electric service.

[4] In addition, Senate Bill 547 reforms Chapter 704B of the Nevada Revised Statutes. The legislation obviously is intended to change the status quo for large commercial and industrial customers to directly access wholesale markets. While the Commission must undertake a rulemaking proceeding to implement the legislation, the bill should result in a more orderly and structured procedure for direct access proceedings, providing additional certainty to support long-term resource planning.

[5] The storage capacity figures represent the maximum capacity the battery can sustain for four hours. The solar capacity figures are 20 percent of the project's maximum capacity. Combined they represent the three new projects' contribution to the loads and resources table.

Similarly, SB254 that was also a result of the 80th Legislature and signed by Governor Sisolak requires the State Department of Conservation and Natural Resources to inventory and report annually on greenhouse gas emissions for four industrial sectors including electricity production. SB254 also requires the State to develop a statement of policies including without limitation regulations to achieve carbon reductions including a qualitative assessment of whether the policies support the long-term reduction of greenhouse gas emissions to zero by the year 2050.

3. The Amendment provides optionality necessary to meet evolving customer needs.

Customers are demanding higher levels of renewables to achieve individual and corporate sustainability goals while at the same time providing stable electricity pricing. Renewable energy has significantly dropped in price particularly in the cost of solar. The use of renewable resources at the customer level has promulgated from rooftop solar, to large customers constructing their own facilities, to now, as a result of Assembly Bill 465 ("AB465"), community solar. AB465 provides for customers that had limited access to solar to now be able to take advantage of solar priced at large utility scale and smaller systems located within the communities. NV Energy has responded to these customer needs and will continue to work with customers to meet their requirements. NV Energy has entered into the three PPAs proposed in this amendment not only to meet the expanded RPS but to also offer incremental renewable resources to customers. NV Energy will continue to respond to customer demands and will be filing with the PUCN further customer driven tariffs that offer market based rates in conjunction with these renewable resources and offering stable pricing based on the cost of the renewable PPAs through the an optional pricing program.

4. The Amendment reduces the Companies open capacity position with cost-effective, long-term commitments that enhance price stability for customers.

Historically, resource planning decisions turned almost exclusively on cost. The present worth of revenue requirement ("PWRR") often was dispositive even though regulations also require the consideration of the present worth of societal cost ("PWSC"). Moreover, supply-side decisions often had a single root, especially those involving the addition of renewable energy. Long-term renewable energy power purchase agreements were brought forth, for example, to meet the requirements of the Public Utilities Regulatory Policy Act; or, the Companies' requested approval of long-term power purchase agreements for purpose of satisfying Nevada's renewable portfolio standard. Likewise, conventional resources were added to reduce the Companies' open capacity position.

In light of the evolving energy industry and policy landscape, decisions become more complex and nuanced. Supply-side planning needs to take into consideration multiple "needs." Good supply-side plans will advance several objectives, all while pursuing both the lowest PWRR and PWSC. This is especially relevant when the State's objective is to improve "air quality," "water use" and "fossil fuel consumption" while providing more "stable rates for retail customers of electric service." The Amendment does exactly that – it accounts for the "needs" of multiple stakeholders and constituents. From a traditional resource planning perspective, the plan enhances reliability, reduces risk, and improves price stability (*i.e.*, reduces volatility) through fixed pricing and increases the diversity of the Companies' supply-side portfolio.

The renewable PPAs for which approvals are sought in this Third Amendment result in changes to the loads and resources (capacity or energy) and have been analyzed utilizing production cost modeling. Thus, consistent with Nevada Administrative Code ("NAC") § 704.9516(1), which sets forth the requirements of an amendment to an approved Action Plan, an updated current peak demand forecast and a current loads and resources table are provided. The PPAs requested in this Third Amendment will increase the Companies' off-balance sheet obligations and will likely result in a higher level of debt imputed by the rating agencies in their credit assessments; however, neither of these outcomes are expected to have a material adverse impact on the Companies' ability to raise capital and finance their operations.

5. Approval of the Amendment benefits all Nevadans.

The results of the 2019 Renewable RFP and the Preferred Plan provide an opportunity to refocus integrated resource planning on long-term objectives: adding cost-effective renewable resources while, at the same time reducing carbon emissions and the Companies' open position through long-term (instead of short-run) commitments. The long-term obligations incorporated into the Preferred Plan enhance reliability, reduce risk, improve price stability through fixed pricing and increase the diversity of the Companies' supply-side portfolio. Equally important, the Preferred Plan provides a solid foundation for developing alternative pricing plans that existing and new large commercial and industrial customers' value, while securing resources that reduce the overall cost of electricity in a way that also benefits mass market (*i.e.*, residential and small commercial) customers.

SECTION 2. SUMMARY OF SPECIFIC APPROVALS REQUESTED

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 Companies' request to amend their 2019-2021 Supply-Side Action Plan to enter into the following three new renewable PPAs:

    a. Nevada Power's PPA with Southern Bighorn Solar Farm for 300 megawatts ("MW") (nameplate, AC) of solar PV generation, with an additional 135 MW capacity of co-located battery storage. Commercial operation is expected by September 1, 2023;

    b. Nevada Power's PPA with Moapa Solar for 200 MW (nameplate, AC) of solar PV generation, with an additional 75 MW capacity of co-located battery storage. Commercial operation is expected by December 1, 2022; and

    c. Nevada Power's PPA with Gemini Solar for 690 MW (nameplate, AC) of solar PV generation, with an additional 380 MW capacity of co-located battery storage. Commercial operation is expected by December 1, 2023.

2. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $1.30 million to construct network upgrades needed to support the interconnection of the Moapa Solar project at the Harry Allen Substation.

3. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $3.67 million to construct network upgrades needed to interconnect the Southern Bighorn Solar project at the Reid Gardner Substation.

4. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $15.63 million to construct network upgrades needed to support the interconnection of Gemini Solar project at Crystal Substation.

5. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $13.42 million to construct a new 230 kilovolt ("kV") substation at the Apex Industrial Park to serve new load, and accommodate additional transmission interconnections and distribution transformers.

6. Approval of the Companies' request to amend their 2019-2021 Transmission Action Plan to expend approximately $6.20 million to add three 230 kV breakers at the existing Machacek substation, to provide increased customer reliability and address a potential safety hazard at the substation.

SECTION 3. LOAD FORECAST

A. Summary of the Third Amendment Load Forecast

The 2019 IRP Second Amendment Forecast ("2019 IRPA 2nd Forecast") was completed in February 2019 and covers calendar years 2020 through 2039. The 2019 IRPA 2nd Forecast was filed in the Second Amendment to the Joint 2018 IRP, Docket No. 19-05003, and is pending approval by the Commission. For this Third Amendment filing, the Companies developed an NRS Chapter 704B all-eligible load forecast to show the impact on the forecast if all eligible customers under Chapter 704B were to transition to distribution only service ("All Eligible Forecast"). The Companies are not asking the Commission approve or act on the All Eligible Forecast, but provide it for informational purposes only.

For Nevada Power, the All Eligible Forecast results in a reduction of about 400 MW (7 percent) from the 2019 IRPA 2nd Forecast and 2,500 gigawatt-hours ("GWh") (12 percent) of annual total sales. Sales reductions include the removal of the new Resorts World hotel/casino property scheduled to open in 2021. Along with the reduction in sales, commercial Demand Side Management ("DSM") savings will be reduced by about 7 percent from the 2019 IRPA 2nd Forecast.

For Sierra, the All Eligible Forecast results in a reduction of 239 MW (13.4 percent) in 2020 rising to 341 MW (19.5 percent) by 2025. Sales are reduced by about 2,100 GWH in 2020 (12.3 percent) and 3,100 GWH (32 percent) by 2025. The reductions increase through time as load increases for Tesla, Apple, and others are removed from the 2019 IRPA 2nd Forecast. The commercial DSM savings will be reduced by about 21 percent by 2025 compared to the 2019 IRPA 2nd Forecast.

B. Methodology to Create the All Eligible Forecast

The 704B all eligible load forecast was developed from the 2019 IRPA 2nd Forecast. A list of Chapter 704B eligible governmental and nongovernmental customers was prepared for the All Eligible Forecast. The customer list included: 1) all nongovernmental customers with an annual consumption greater than 8,760 MWh and greater than one MW billing demand; 2) government customers in the Companies' Large commercial and industrial ("Large C&I") class, and 3) for Nevada Power, governmental customers on the Public Authority rate. Due to the unreasonable time commitment to determine the geographical proximity of all eligible customers, the Companies did not attempt to identify contiguously-premised load of non-Large C&I customers. Hourly load data was extracted for each of these customers for the year ending December 31, 2016, for NPC and August 31, 2018, for Sierra. These time periods were the most current vetted data for each Company. The NPC hourly data was then scaled to the billing data for the year ending August 31, 2018.

Table LF-1 shows the rate classes that were included in the analysis:

TABLE LF-1
RATE CLASSES INCLUDED IN THE ALL ELIGIBLE LIST

Nevada Power	Sierra
LGS3-P	GS3-S
OLGS3-P-HLF	GS3-P
LGS3-S	GS3-T
LGS3-T	LSR3-T
LGS2-P	GS4
LGS2-S	GS4NG
LGS2-T	GS3NG
LS R3-T	
All bundled Public Authority rates	

The Companies then calculated the annual sales before DSM. The sales were calculated by reducing the base case sales before DSM by the all eligible sales, and then the DSM savings were calculated in the same manner as for the base case. The Companies used the same percent targets for the All Eligible Forecast as were used for the base case. The Companies fixed the residential class DSM at the base case savings, and adjusted only commercial DSM. The commercial intensities were adjusted using the all eligible DSM, and the DSM-adjusted sales regressions for the Small and Large C&I classes were used to calculate the all eligible sales. Adjustments for private generation, demand response, and electric vehicles were made to those sales. All of these sales adjustments are the same as the base case.

As in the 2019 IRPA 2nd Forecast, the peak models were then used to develop the forecasted monthly peaks and energy before adjustments for private generation, electric vehicles, demand response, and exiting customer loads, using the forecasted sales from the class models. These monthly MW and MWh were then imposed on the normalized system profiles to create the hourly loads before adjustments. These hourly loads would be the same as the 2019 IRPA 2nd forecast except for the lower commercial DSM reductions calculated from the commercial class sales reduced by the all eligible customer sales.

The Companies then developed weather-normalized load shapes based on historical hourly load research data for the rates listed in Table LF-1 to be used to subtract the all eligible hourly load from the system hourly load before adjustments. As done in previous forecasts, rates were combined at Nevada Power where migration has occurred in the past.

The monthly MWh by rate of the all eligible customers was then imposed on the applicable hourly normalized load shapes. The loads were then scaled up for losses by voltage level per the Open Access Transmission Tariff ("OATT") percentages. These load shapes were then subtracted along with the 2019 IRPA 2nd forecast base case adjustments from the system hourly load forecast before adjustments to develop the 704B all eligible hourly loads and peak demands.

Tables LF-2 through LF-6 compare the base and all eligible load forecasts peak, native energy, sales, DSM savings, and Loads and Resources components. Note that the peak, energy, and sales differences rise through 2025 before stabilizing. This is a result of removing increases for large customers growing during that time period in the base case.

TABLE LF-2
COMPARISON OF PEAK MW: BASE CASE VS. ALL ELIGIBLE

	SUMMER PEAK (MW)								
	Base Case			All Eligible 704B			Difference to Base		
Year	NVE (1)	NPC (2)	SPPC (2) (3)	NVE (1)	NPC (2)	SPPC (2) (3)	NVE (1)	NPC (2)	SPPC (2) (3)
2020	7,468	5,696	1,787	6,836	5,304	1,548	(632)	(392)	(239)
2021	7,501	5,778	1,814	6,831	5,380	1,548	(670)	(398)	(266)
2022	7,404	5,825	1,695	6,734	5,428	1,408	(670)	(397)	(287)
2023	7,553	5,853	1,714	6,816	5,432	1,407	(737)	(421)	(307)
2024	7,615	5,891	1,737	6,853	5,469	1,408	(763)	(422)	(329)
2025	7,662	5,923	1,749	6,896	5,511	1,408	(766)	(412)	(341)
2026	7,687	5,953	1,750	6,924	5,541	1,405	(763)	(412)	(345)
2027	7,656	5,998	1,752	6,916	5,611	1,408	(740)	(387)	(344)
2028	7,769	6,023	1,756	7,003	5,615	1,415	(766)	(408)	(341)
2029	7,809	6,064	1,761	7,048	5,654	1,422	(762)	(410)	(339)
2030	7,856	6,101	1,768	7,091	5,690	1,428	(765)	(411)	(340)
2031	7,903	6,140	1,777	7,142	5,731	1,437	(762)	(409)	(340)
2032	7,950	6,178	1,788	7,188	5,770	1,448	(762)	(408)	(340)
2033	7,908	6,209	1,798	7,171	5,825	1,458	(736)	(384)	(340)
2034	8,037	6,246	1,809	7,280	5,840	1,469	(757)	(406)	(340)
2035	8,085	6,286	1,818	7,329	5,880	1,479	(756)	(406)	(339)
2036	8,157	6,341	1,831	7,409	5,945	1,491	(748)	(396)	(340)
2037	8,200	6,385	1,840	7,449	5,976	1,501	(751)	(409)	(339)
2038	8,175	6,430	1,853	7,450	6,054	1,514	(725)	(376)	(339)
2039	8,226	6,465	1,866	7,496	6,087	1,527	(730)	(378)	(339)

(1) Adjusted for Diversity.
(2) Company coIncident peak.
(3) Liberty Energy becomes a balancing authority customer on 5/1/2019
and a large mine customer transitions to DOS on 2/1/2022.

TABLE LF-3
COMPARISON OF NATIVE ENERGY (GWH): BASE CASE VS. ALL ELIGIBLE

	NV Energy				NPC				Sierra			
Year	Base	All Eligible	Change	% Change	Base	All Eligible	Change	% Change	Base	All Eligible	Change	% Change
2019	30,649	30,649	0		20,711	20,711	0		9,938	9,938	0	
2020	30,505	25,910	(4,594)	-15.1%	20,536	18,111	(2,424)	-11.8%	9,969	7,799	(2,170)	-21.8%
2021	30,960	26,025	(4,935)	-15.9%	20,745	18,224	(2,522)	-12.2%	10,215	7,801	(2,413)	-23.6%
2022	30,383	25,141	(5,242)	-17.3%	20,997	18,372	(2,625)	-12.5%	9,386	6,769	(2,616)	-27.9%
2023	30,485	25,058	(5,427)	-17.8%	21,095	18,478	(2,617)	-12.4%	9,390	6,580	(2,810)	-29.9%
2024	30,828	25,199	(5,630)	-18.3%	21,209	18,594	(2,615)	-12.3%	9,620	6,605	(3,015)	-31.3%
2025	30,994	25,275	(5,719)	-18.5%	21,271	18,671	(2,600)	-12.2%	9,723	6,603	(3,119)	-32.1%
2026	31,101	25,366	(5,736)	-18.4%	21,342	18,751	(2,592)	-12.1%	9,759	6,615	(3,144)	-32.2%
2027	31,188	25,467	(5,721)	-18.3%	21,418	18,835	(2,583)	-12.1%	9,770	6,631	(3,138)	-32.1%
2028	31,330	25,601	(5,729)	-18.3%	21,528	18,940	(2,588)	-12.0%	9,802	6,661	(3,141)	-32.0%
2029	31,422	25,711	(5,711)	-18.2%	21,609	19,029	(2,580)	-11.9%	9,813	6,682	(3,132)	-31.9%
2030	31,470	25,761	(5,709)	-18.1%	21,648	19,069	(2,578)	-11.9%	9,822	6,691	(3,131)	-31.9%
2031	31,523	25,816	(5,707)	-18.1%	21,695	19,118	(2,577)	-11.9%	9,828	6,698	(3,130)	-31.8%
2032	31,635	25,916	(5,720)	-18.1%	21,768	19,187	(2,582)	-11.9%	9,867	6,729	(3,138)	-31.8%
2033	31,682	25,980	(5,702)	-18.0%	21,810	19,236	(2,574)	-11.8%	9,872	6,744	(3,128)	-31.7%
2034	31,790	26,091	(5,699)	-17.9%	21,879	19,307	(2,572)	-11.8%	9,911	6,784	(3,127)	-31.6%
2035	31,900	26,203	(5,697)	-17.9%	21,955	19,385	(2,570)	-11.7%	9,945	6,818	(3,127)	-31.4%
2036	32,063	26,354	(5,709)	-17.8%	22,063	19,488	(2,575)	-11.7%	10,000	6,866	(3,134)	-31.3%
2037	32,145	26,454	(5,691)	-17.7%	22,129	19,563	(2,566)	-11.6%	10,015	6,891	(3,124)	-31.2%
2038	32,270	26,582	(5,688)	-17.6%	22,218	19,653	(2,565)	-11.5%	10,053	6,929	(3,124)	-31.1%
2039	32,415	26,730	(5,685)	-17.5%	22,322	19,759	(2,563)	-11.5%	10,094	6,971	(3,122)	-30.9%

TABLE LF-4
COMPARISON OF TOTAL SALES (GWH): BASE CASE VS. ALL ELIGIBLE

	NV ENERGY				NPC				Sierra (not including California)			
Year	Base	All Eligible	Change	% Change	Base	All Eligible	Change	% Change	Base	All Eligible	Change	% Change
2019	28,895	28,895	0		19,792	19,792	0		9,104	9,104	0	
2020	28,974	24,560	(4,413)	-15.2%	19,614	17,281	(2,333)	-11.9%	9,360	7,279	(2,081)	-22.2%
2021	29,424	24,663	(4,761)	-16.2%	19,812	17,373	(2,438)	-12.3%	9,613	7,290	(2,323)	-24.2%
2022	28,863	23,809	(5,054)	-17.5%	20,050	17,519	(2,532)	-12.6%	8,813	6,290	(2,522)	-28.6%
2023	28,951	23,715	(5,236)	-18.1%	20,142	17,618	(2,524)	-12.5%	8,809	6,097	(2,712)	-30.8%
2024	29,268	23,848	(5,420)	-18.5%	20,248	17,732	(2,516)	-12.4%	9,020	6,116	(2,904)	-32.2%
2025	29,434	23,905	(5,529)	-18.8%	20,306	17,792	(2,514)	-12.4%	9,128	6,113	(3,015)	-33.0%
2026	29,532	23,991	(5,541)	-18.8%	20,372	17,872	(2,500)	-12.3%	9,160	6,118	(3,042)	-33.2%
2027	29,611	24,082	(5,530)	-18.7%	20,443	17,952	(2,492)	-12.2%	9,168	6,130	(3,038)	-33.1%
2028	29,734	24,209	(5,525)	-18.6%	20,547	18,056	(2,490)	-12.1%	9,187	6,153	(3,034)	-33.0%
2029	29,823	24,295	(5,527)	-18.5%	20,623	18,128	(2,495)	-12.1%	9,199	6,167	(3,033)	-33.0%
2030	29,864	24,344	(5,520)	-18.5%	20,659	18,172	(2,487)	-12.0%	9,205	6,173	(3,032)	-32.9%
2031	29,916	24,399	(5,518)	-18.4%	20,703	18,217	(2,486)	-12.0%	9,213	6,182	(3,032)	-32.9%
2032	30,007	24,492	(5,516)	-18.4%	20,773	18,288	(2,485)	-12.0%	9,234	6,203	(3,031)	-32.8%
2033	30,056	24,536	(5,520)	-18.4%	20,812	18,323	(2,489)	-12.0%	9,244	6,214	(3,030)	-32.8%
2034	30,144	24,632	(5,512)	-18.3%	20,878	18,396	(2,482)	-11.9%	9,266	6,237	(3,030)	-32.7%
2035	30,242	24,732	(5,509)	-18.2%	20,950	18,470	(2,480)	-11.8%	9,292	6,262	(3,029)	-32.6%
2036	30,379	24,872	(5,507)	-18.1%	21,052	18,573	(2,479)	-11.8%	9,327	6,299	(3,029)	-32.5%
2037	30,463	24,952	(5,511)	-18.1%	21,115	18,632	(2,483)	-11.8%	9,348	6,320	(3,028)	-32.4%
2038	30,573	25,071	(5,502)	-18.0%	21,199	18,724	(2,475)	-11.7%	9,374	6,346	(3,027)	-32.3%
2039	30,703	25,203	(5,500)	-17.9%	21,298	18,825	(2,473)	-11.6%	9,405	6,378	(3,027)	-32.2%

TABLE LF-5
COMPARISON OF COMMERCIAL DSM SAVINGS (GWH): BASE CASE VS. ALL ELIGIBLE

	NV Energy				NPC				Sierra			
Year	Base	All Eligible	Change	% Change	Base	All Eligible	Change	% Change	Base	All Eligible	Change	% Change
2020	499	486	(13)	-2.6%	366	353	(13)	-3.5%	133	133	0	0.0%
2021	765	738	(27)	-3.5%	558	531	(27)	-4.8%	207	207	0	0.0%
2022	1,027	962	(65)	-6.3%	752	710	(42)	-5.6%	275	252	(23)	-8.3%
2023	1,291	1,185	(105)	-8.2%	948	890	(58)	-6.2%	343	295	(47)	-13.8%
2024	1,557	1,409	(148)	-9.5%	1,145	1,070	(74)	-6.5%	412	339	(73)	-17.8%
2025	1,825	1,634	(191)	-10.5%	1,343	1,252	(90)	-6.7%	482	382	(101)	-20.9%
2026	2,094	1,860	(235)	-11.2%	1,541	1,435	(106)	-6.9%	553	425	(128)	-23.2%
2027	2,364	2,087	(278)	-11.8%	1,740	1,618	(122)	-7.0%	624	468	(156)	-25.0%
2028	2,636	2,315	(321)	-12.2%	1,940	1,802	(138)	-7.1%	695	512	(183)	-26.4%
2029	2,908	2,544	(365)	-12.5%	2,141	1,988	(154)	-7.2%	767	556	(211)	-27.5%
2030	3,181	2,774	(407)	-12.8%	2,343	2,174	(169)	-7.2%	838	600	(238)	-28.4%
2031	3,454	3,005	(449)	-13.0%	2,544	2,361	(183)	-7.2%	910	644	(266)	-29.2%
2032	3,729	3,237	(491)	-13.2%	2,747	2,549	(198)	-7.2%	982	688	(294)	-29.9%
2033	4,003	3,471	(533)	-13.3%	2,950	2,738	(212)	-7.2%	1,054	732	(321)	-30.5%
2034	4,279	3,705	(574)	-13.4%	3,153	2,928	(225)	-7.1%	1,126	777	(349)	-31.0%
2035	4,556	3,941	(615)	-13.5%	3,358	3,119	(239)	-7.1%	1,198	822	(376)	-31.4%
2036	4,834	4,178	(656)	-13.6%	3,563	3,311	(252)	-7.1%	1,271	867	(404)	-31.8%
2037	5,112	4,416	(696)	-13.6%	3,769	3,504	(265)	-7.0%	1,344	912	(431)	-32.1%
2038	5,392	4,655	(737)	-13.7%	3,976	3,698	(278)	-7.0%	1,417	958	(459)	-32.4%
2039	5,674	4,896	(778)	-13.7%	4,183	3,892	(291)	-7.0%	1,490	1,004	(486)	-32.6%

TABLE LF-6
COMPARISON OF L&R COMPONENTS (MW): BASE CASE VS. ALL ELIGIBLE[6]

	AVOIDED CAPACITY (DR)				INCREMENTAL DSM			
	NPC		SPPC		NPC		SPPC	
Year	Base	All Eligible	Base	All Eligible	Base	All Eligible	Base	All Eligible
2020	168	169	31	30	76	72	25	25
2021	192	191	37	35	113	108	39	39
2022	197	196	42	40	150	144	52	49
2023	189	189	47	44	188	180	65	59
2024	191	195	49	47	226	216	78	69
2025	201	197	52	50	264	253	91	79
2026	201	199	56	55	302	290	104	89
2027	215	215	57	57	343	327	118	99
2028	206	203	59	57	384	364	132	109
2029	206	206	61	58	425	401	146	119
2030	204	204	64	61	467	439	160	129
2031	213	214	65	62	509	477	174	139
2032	214	213	66	64	551	515	188	149
2033	227	226	64	63	593	553	202	159
2034	216	214	65	63	635	591	216	169
2035	220	219	65	62	677	629	230	179
2036	226	216	67	66	720	668	244	189
2037	217	220	67	66	763	707	258	199
2038	238	234	67	65	806	746	272	209
2039	239	237	67	65	849	785	286	219

[6] The private generation and the installed DR capacity did not change from the base case.

SECTION 4. AMENDMENTS TO SUPPLY-SIDE PLAN (RENEWABLE)

A. Long-term Purchase Power Agreements

The Companies meet the energy demand of its customers with Company-owned and controlled generation, as well as with a combination of long-term power purchase agreements ("PPAs") and short-term energy transactions.

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

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

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

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date
Renewable Purchase Agreements				
PPAs (Commercial)				
ACE Searchlight[QF]	Solar[S]	17.5	12/16/2014	12/31/2034
APEX Landfill[QF]	Methane	12.0	3/1/2012	12/31/2032
Boulder Solar I[EWG]	Solar[S]	100.0	12/9/2016	12/31/2036
Colorado River Commission-Hoover	Hydro	237.6	10/1/2017	9/30/2067
Desert Peak 2[QF]	Geothermal	25.0	4/17/2007	12/31/2027
FRV Spectrum[QF]	Solar[S]	30.0	9/23/2013	12/31/2038
Jersey Valley[QF]	Geothermal	22.5	8/30/2011	12/31/2031
McGinness Hills[QF]	Geothermal	96.0	6/20/2012	12/31/2032
Mountain View[EWG]	Solar[S]	20.0	1/5/2014	12/31/2039
Nevada Solar One (NPC)[QF]	Solar[T,X]	46.9	6/27/2007	12/31/2027
NGP Blue Mountain[QF]	Geothermal	49.5	11/20/2009	12/31/2029
RV Apex[QF]	Solar[S]	20.0	7/21/2012	12/31/2037
Salt Wells[QF]	Geothermal	23.6	9/18/2009	12/31/2029
Silver State[EWG]	Solar[F]	52.0	4/25/2012	12/31/2037
Spring Valley[EWG]	Wind	151.8	8/16/2012	12/31/2032
Stillwater Geothermal[1,QF]	Geothermal	47.2	10/10/2009	12/31/2029
Stillwater PV[1,QF]	Solar[F]	22.0	3/5/2012	12/31/2029
Switch Station 1[EWG]	Solar[S]	100.0	8/8/2017	12/31/2037
Switch Station 2 (NPC)[EWG]	Solar[S]	0.0	10/11/2017	12/31/2037
Techren I[EWG]	Solar[S]	100.0	3/11/2019	12/31/2044
Tonopah Crescent Dunes[EWG]	Solar[T,X]	110.0	11/9/2015	12/31/2040
Tuscarora[QF]	Geothermal	32.0	1/11/2012	12/31/2032
WM Renewable Energy-Lockwood[QF]	Methane	3.2	4/1/2012	12/31/2032
		1318.8		
PC Purchase Agreements				
NPC-SPPC	Geothermal	2.3	10/30/2009	12/31/2028
Nellis I (Solar Star)	Solar	13.2	12/15/2007	12/31/2027
SunPower (LVVWD)	Solar	3.0	4/20/2006	12/31/2026
		18.5		
PPAs (Pre-Commercial)[2]				
Techren III[QF]	Solar[S]	25.0	9/1/2020	12/31/2045
Techren V[EWG]	Solar[S]	50.0	1/1/2021	12/31/2045
Copper Mountain 5	Solar[S]	250.0	1/1/2022	12/31/2046
Eagle Shadow Mountain	Solar[S]	300.0	1/1/2022	12/31/2046
		625.0		
Non-Renewable Purchase Agreements				
Nevada Cogeneration Associates #1[QF]	Natural Gas	85.0	6/18/1992	4/30/2023
Nevada Cogeneration Associates #2[QF]	Natural Gas	85.0	2/1/1993	4/30/2023
Saguaro Power Company[QF]	Natural Gas	90.0	10/17/1991	4/30/2022
		260.0		
Renewable and Non-Renewable Sales Agreements				
City of Las Vegas NGR (Boulder Solar I)	NGR Agreement (Sale of PCs)	See Note 3	12/9/2016	12/8/2019
Switch NGR (Switch Station 1)	NGR Agreement (Sale of PCs)	100.0	8/8/2017	12/31/2037
Switch NGR-NPC (Switch Station 2)	NGR Agreement (Sale of PCs)	0.0	10/11/2017	12/31/2037
Notes:				
1. The geothermal and solar facilities are combined into one PPA.				
2. Facilities are either under development or construction (the dates shown are expected dates).				
3. NPC shall sell 43,200 kPCs per year for three years.				
QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt, X=Storage				

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

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date
Renewable Energy				
PPAs (Commercial)				
Beowawe[QF]	Geothermal	17.7	4/21/2006	12/31/2025
Boulder Solar II[EWG]	Solar[S]	50.0	1/27/2017	12/31/2037
Brady[QF]	Geothermal	24.0	7/30/1992	7/29/2022
Burdette[QF]	Geothermal	26.0	2/28/2006	12/31/2026
Galena 3[QF]	Geothermal	26.5	2/21/2008	12/31/2028
Homestretch[QF]	Geothermal	5.58	6/1/1987	12/31/2019
Hooper[1,QF]	Hydro	0.75	6/23/2016	12/31/2040
Kingston[1]	Hydro	0.175	9/19/2011	12/31/2040
Mill Creek[1]	Hydro	0.037	9/1/2011	12/31/2040
Nevada Solar One (SPPC)[QF]	Solar[T,X]	22.1	6/27/2007	12/31/2027
RO Ranch[1,2]	Hydro	0	3/15/2011	12/31/2040
Rye Patch[1]	Hydro	0.75	5/2/2019	12/31/2040
Soda Lake II[QF]	Geothermal	19.5	8/4/1991	8/4/2021
Steamboat 2[QF]	Geothermal	13.4	12/13/1992	12/12/2022
Steamboat 3[QF]	Geothermal	13.4	12/19/1992	12/18/2022
Switch Station 2 (SPPC)[EWG]	Solar[S]	79.0	10/11/2017	12/31/2037
TCID New Lahontan[QF]	Hydro	4.0	6/12/1989	6/11/2039
TMWA Fleish	Hydro	2.4	5/16/2008	6/1/2028
TMWA Verdi	Hydro	2.4	5/15/2009	6/1/2029
TMWA Washoe	Hydro	2.5	7/25/2008	6/1/2028
USG San Emidio[QF]	Geothermal	11.75	5/25/2012	12/31/2037
		321.9		
Leased Units				
Fort Churchill Solar[5]	Solar[S]	19.5	8/5/2015	8/4/2040
PC Purchase Agreement				
TMWRF	Methane	0.8	9/9/2005	12/12/2024
PPAs (Pre-Commercial)[3]				
Techren II[EWG]	Solar[S]	200.0	9/1/2019	12/31/2044
Techren IV[QF]	Solar[S]	25.0	9/1/2020	12/31/2045
Turquoise	Solar[F]	50.0	11/1/2020	12/31/2045
Battle Mountain	Solar[S,X=25MW]	101.0	7/1/2021	12/31/2046
Dodge Flat	Solar[S,X=50MW]	200.0	12/1/2021	12/31/2046
Fish Springs Ranch	Solar[S,X=25MW]	100.0	12/1/2021	12/31/2046
		676.0		
Non-Renewable Purchase Agreements				
Newmont Nevada Energy Investment	Coal	174.0	6/1/2008	1/31/2022
Liberty (CalPeco) EBSA	Diesel	12.0	1/1/2011	12/31/2031
		186.0		
Renewable & Non-Renewable Sales Agreements				
Liberty (CalPeco)	Full Requirements (Capacity/Energy/PCs)	See Note 4	1/1/2016	12/30/2020
NPC-SPPC	Sale of PCs (Geothermal)	2.3	10/30/2009	12/31/2028
Truckee Meadows Community College NGR (Techern I)	NGR Agreement (Sale of PCs)	See Note 6	9/1/2019	8/31/2022
Apple NGR (Fort Churchill Solar)	NGR Agreement (Sale of PCs)	19.5	8/5/2015	8/4/2040
Apple NGR (Boulder Solar II)	NGR Agreement (Sale of PCs)	50.0	1/27/2017	12/31/2037
Switch NGR-SPPC (Switch Station 2)	NGR Agreement (Sale of PCs)	79.0	10/11/2017	12/31/2037
Apple NGR (Techren II)[3]	NGR Agreement (Sale of PCs)	200.0	9/1/2019	12/31/2044
Apple NGR (Turquoise)[3]	NGR Agreement (Sale of PCs)	50.00	11/1/2020	12/31/2045

Notes:
1. The illustrative termination date shown is subject to certain conditions, which may result in termination before or after December 31, 2040.
2. RO Ranch Hydro facility is shut down indefinitely (the PPA is still active).
3. Facilities are either under development or construction (the dates shown are expected dates).
4. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December). Termination Discussions are Active.
5. Option to purchase on January 1, 2021.
6. SPPC shall sell 7,200 kPCs per year for three years after PUCN approval.

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

1. RENEWABLE PPAs

Nevada Power has executed 28 long-term renewable PPAs representing a total nameplate capacity of approximately 1,944 MW (*see*, Figure CON-1 above). The latest commercial addition to the portfolio is the Techren I solar project, which achieved commercial operation in March 2019. The Techren Solar III (25 MW), Techren Solar V (50 MW), Copper Mountain Solar 5, and the Eagle Shadow Mountain Solar (300 MW) projects are expected to achieve commercial operation in September 2020, January 2021, January 2022, and January 2022, respectively. Nevada Power has executed three long-term PC-only purchase agreements representing a total nameplate capacity of approximately 18.5 MW. Nevada Power's renewable PPAs secure a renewable energy portfolio that is made up of a mix of solar, geothermal, hydro, methane, and wind resources.

Sierra has executed 27 long-term renewable PPAs representing a total nameplate capacity of approximately 998 MW (*see*, Figure CON-2 above). The latest commercial addition to the portfolio is the Rye Patch Dam project, which achieved commercial operation in May 2019. The Techren Solar II (200 MW), Techren Solar IV (25 MW), Turquoise Solar (50 MW), Battle Mountain Solar (101 MW), Dodge Flat Solar (200 MW), and Fish Springs Ranch projects are expected to achieve commercial operation in September 2019, September 2020, November 2020, July 2021, December 2021, and December 2021, respectively. Sierra has executed one long-term PC-only purchase agreement representing a nameplate capacity of 0.8 MW. Sierra's renewable PPAs secure a renewable energy portfolio that is made up of a mix of solar, geothermal, and hydro resources.

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

2. NON-RENEWABLE PPAs

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

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

Sierra has executed two long-term non-renewable PPAs. The first is with Newmont, pursuant to which Sierra purchases 174 MW of dispatchable output from Newmont Mining's coal-fueled facility in northern Nevada. This agreement expires on January 31, 2022. A second PPA is with Liberty Utilities ("Liberty"), pursuant to which Sierra purchases 12 MW of capacity from Liberty's Kings Beach diesel units for emergency purposes. This agreement expires December 31, 2031.

3. RENEWABLE AND NON-RENEWABLE SALES AGREEMENTS

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

Nevada Power has executed three NGR Agreements pursuant to which it sells PCs to the City of Las Vegas (associated with a portion of the Boulder Solar 1 project output) and Switch Ltd. (associated with the full output of the Switch Station 1 project and 35 percent of Switch Station 2 project).

Sierra has executed a full requirements agreement with Liberty pursuant to which Sierra sells capacity, energy, and certain PCs to meet the needs of Liberty retail customers in California. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December). The term of the agreement is January 1, 2016, through December 30, 2020.

Sierra has executed four NGR Agreements for the sale of PCs to Apple (associated with the full output of the Ft. Churchill Solar Array, Boulder Solar II project, Techren Solar II project, and the Turquoise Solar project), a fifth one to Switch Ltd. (associated with the output of the Switch Station 2 project), and a sixth one to Truckee Meadows Community College (associated with the Techren I project) is pending approval with the Commission. Sierra has also executed one long-term agreement for the sale of PCs to Nevada Power. This PC-only sale agreement expires December 31, 2028.

B. Renewable Energy Plan (Renewable Energy Resources)

1. 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 its generating fleet have come a long way in 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.

The Companies have articulated a goal to double the amount of renewable generating capacity by 2023. In the 2018 IRP filing, Docket No. 18-06003, the Companies received approval to add 1,001 MW of new renewable generation capacity to their existing portfolio of projects. In addition, with the enactment of Senate Bill ("SB") 358 into law doubling the RPS to 50 percent starting in 2030, it is imperative that the Companies continue building their renewable generating portfolios.

In their most recent Annual Compliance filing (Docket No. 19-04010), Nevada Power and Sierra both exceeded their 2018 RPS credit requirement of 20 percent, as well as the 2018 solar requirement of 6 percent. Nevada Power ended 2018 at 24.4 percent, a record for Nevada Power, with 50.5 percent of eligible renewable energy credits coming from solar resources. Sierra ended 2018 with 23.7 percent with 33.2 percent of eligible credits coming from solar resources.

As of May 22, 2019, Nevada Power had approximately 1,318 MW of renewable generating resources operating and delivering renewable energy to meet the energy needs of its customers, including the recently commissioned Techren Solar I (100 MW).[7] Several other renewable PPA projects totaling 625 MW are in the development stage: Techren Solar III (25 MW), Eagle Shadow Mountain Solar Farm (300 MW), Copper Mountain Solar 5 (250 MW), and Techren Solar V (50 MW).

[7] The 1,318 MW includes Switch Station I, 100 MW, where Nevada Power uses the energy produced by the facility, but the PCs are dedicated to Switch. The calculation is based on dividing the Nevada Solar One 69 MW output between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission

As of May 22, 2019, Sierra had approximately 322 MW of renewable generating resources operating and delivering renewable energy to meet the energy needs of its customers.[8] In addition to the 322 MW of renewable capacity currently in operation, Sierra has: two renewable projects under construction – Techren Solar II (200 MW) and Turquoise Solar (50 MW); and four projects in the development stage – Techren Solar IV (25 MW), Battle Mountain Solar (101 MW), Dodge Flat Solar (200 MW), and Fish Spring Ranch Solar (100 MW); totaling 676 MW. The Techren Solar II and Turquoise Solar projects are associated with NGR agreements between Apple and Sierra where the credits generated by the projects will be sold to Apple, and, therefore, cannot be used by Sierra to meet its RPS requirement.

The following is a summary of Nevada Power's and Sierra's existing portfolio of renewable facilities that are or will be contributing to meeting Nevada Power's and Sierra's RPS requirements as of April 2019. The list below does not include projects that are dedicated to supporting commitments to meet customer-specific requirements for renewable energy under the NGR program.

Nevada Power

1. Desert Peak 2 Geothermal Project
   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. The PPA is with Nevada Power and terminates on December 31, 2027.

2. The Faulkner 1 Geothermal Project
   The Faulkner 1 (aka NGP Blue Mountain) facility 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. The PPA is with Nevada Power and 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 in both Lander and Pershing counties in Nevada. The project was approved by the Commission in 2007. The plant began producing energy in 2011. The PPA is with Nevada Power and terminates on December 31, 2031.

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

[8] The 322 MW total includes the following NGR Agreements: Fort Churchill (19.5 MW), Boulder Solar II (50 MW), and Switch Station 2 (79 MW). The 322 MW number is also based upon dividing the Nevada Solar One (69 MW) output between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission.

5. Salt Wells Geothermal Project
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 is with Nevada Power and terminates on December 31, 2029.

6. Stillwater 2 Geothermal Project
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 is with Nevada Power and terminates on December 31, 2029.

7. Tuscarora Geothermal Project
The Tuscarora facility is a 32 MW geothermal project located in Elko County, Nevada. The capacity of the facility was amended from 25 MW to 32 MW in Docket No. 12-06053. The plant began producing energy in 2012. The PPA is with Nevada Power and terminates on December 31, 2032.

8. ACE Searchlight Solar Project
The ACE Searchlight facility 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 is with Nevada Power and terminates on December 31, 2034.

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

10. Boulder Solar 1 Project
The Boulder Solar 1 facility is a 100 MW solar PV project located in Boulder City, Nevada. The project was approved by the Commission in 2015. The solar farm completed commissioning and declared commercial operating in December 2016. The 25-year PPA terminates on December 31, 2036. Nevada Power entered into a three-year NGR agreement with the City of Las Vegas whereby a portion of the portfolio energy credits (43,200) kPCs are transferred annually from this facility to the City.[9]

11. Tonopah Crescent Dunes Project
The Tonopah Crescent Dunes facility is a 110 MW solar thermal plant with storage capability located near Tonopah, Nevada. The project was approved by the Commission in 2010. The solar thermal plant completed commissioning and declared commercial operation in November 2015. The PPA terminates on December 31, 2040.

[9] The three year NGR with the City of Las Vegas was approved by the Commission in Docket No. 15-11026

12. Las Vegas Valley Water District ("LVVWD") Project
The LVVWD facility 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. The agreement terminates on December 31, 2026.

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

14. Nellis Air Force Base, Solar Star Project
The Nellis AFB PV facility 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. The agreement terminates on December 31, 2027.

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

16. Nevada Solar One Project
The Nevada Solar One facility is a 69 MW concentrating 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. The PPA terminates on December 31, 2027.

17. Silver State Solar Project
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 farm began producing energy in 2012. The PPA terminates on December 31, 2037.

18. Spectrum Nevada Solar Project
The 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 farm began producing energy in 2013. The PPA terminates on December 31, 2038.

19. Stillwater 2 Solar Project
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 agreement terminates on December 31, 2029.

20. Eagle Shadow Mountain Solar Farm Project (new)
    The Eagle Shadow Mountain Solar Farm facility is a 300 MW AC solar PV facility located on the Moapa River Indian Reservation in Clark County, Nevada. The solar farm is projected to declare commercial operations in January 2022. The project was approved by the Commission in Docket No. 18-06003. When the project achieves commercial operation, the energy and renewable credits produced will be split between Nevada Power (60 percent) and Sierra (40 percent). The PPA is for 25 years.

21. Copper Mountain Solar 5 Project (new)
    The Copper Mountain Solar 5 facility is a 250 MW AC solar PV facility located in Boulder City, Nevada. The solar farm is projected to declare commercial operations in January 2022. The project was approved by the Commission in Docket No. 18-06003. When the project achieves commercial operation, the energy and renewable credits produced will be split between Nevada Power (60 percent) and Sierra (40 percent). The PPA is for 25 years.

22. Techren Solar I Project
    The Techren Solar I facility is a 100 MW AC solar PV facility located in Boulder City, Nevada. The solar farm achieved commercial operation March 11, 2019. The project was approved by the Commission in Docket No. 16-08026. The PPA is for 25 years.

23. Techren Solar III Project
    The Techren Solar III facility is a 25 MW AC solar PV facility located in Boulder City, Nevada. The solar farm is projected to declare commercial operation in the third quarter of 2020. The project was approved by the Commission in Docket No. 17-11004. The PPA is for 25 years.

24. Techren Solar V Project (new)
    The Techren Solar V facility is a 50 MW AC solar PV facility located in Boulder City, Nevada. The solar farm is projected to declare commercial operation in January 2021. The project was approved by the Commission in Docket No. 18-06003. When the project achieves commercial operation, the energy and renewable credits produced will be split between Nevada Power (60 percent) and Sierra (40 percent). The PPA is for 25 years.

25. Spring Valley Wind Project
    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.

26. Apex Landfill Project
    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.

27. Lockwood Renewable Energy Landfill Project
    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.

28. Goodsprings Recovered Energy Generation Station Project

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

Sierra

1. Beowawe Geothermal Project

   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. In 2006, Sierra entered into a 20-year contract for renewable energy that expires on April 21, 2025.

2. Brady Geothermal Project

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

3. Burdette Geothermal Project

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

4. Galena 3 Geothermal Project

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

5. Homestretch Geothermal Project

   The Homestretch facility, aka White Grass 1, is a 5.58 MW geothermal project located in Lyon County north of Yerington, Nevada. Sierra originally entered into separate contracts for three small Homestretch geothermal plants that totaled 2.1 MW. Sierra obtained Commission approval to aggregate and expand the output under the contract in Docket No. 09-01016; the original long-term contract expired in 2017. It was extended for 2018, and again for 2019. Assuming that it is not further extended, the PPA is set to expire on December 31, 2019.

6. Soda Lake 2 Geothermal Project

   The Soda Lake 2 facility is 19.5 MW geothermal project located in Churchill County east of Fallon, Nevada. The PPA originally covered two plants, Soda Lake 1 and Soda Lake 2. The Soda Lake 1 PPA, the smaller of the two generating units at 3.6 MW, expired in 2017 but was extended through 2018. At the end of 2018, the plant was taken out of service by the owner. Sierra's PPA with the remaining unit, Soda Lake 2, is scheduled to expire on August 4, 2021.

7. Steamboat 2 Geothermal Project
   The Steamboat 2 facility is a 13.4 MW geothermal project located in Washoe County, NV. The plant began producing energy in 1992. Sierra has a 30 year contract with the facility that expires on December 12, 2022.

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

9. USG San Emidio Geothermal Project
   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. Sierra has a 25 year contract with the facility that expires on December 31, 2037.

10. Battle Mountain Solar Project (new)
    The Battle Mountain Solar facility is a 101 MW AC solar PV facility located near Battle Mountain, Nevada. The project incorporates 25 MW of battery storage. The solar farm is projected to declare commercial operation in July 2021. The project was approved by the Commission in Docket No. 18-06003. When the solar farm achieves commercial operation, the energy and renewable credits produced will be split between Nevada Power (60 percent) and Sierra (40 percent). The PPA is for 25 years.

11. Dodge Flat Solar Project (new)
    The Dodge Flat Solar facility is a 200 MW AC solar PV facility located in Washoe County, Nevada. The project incorporates 50 MW of battery storage. The solar farm is projected to declare commercial operations in December 2021. The project was approved by the Commission in Docket No. 18-06003. When the solar farm achieves commercial operation, the energy and renewable credits produced will be split between Nevada Power (60 percent) and Sierra (40 percent). The PPA is for 25 years.

12. Fish Springs Ranch Solar Project (new)
    The Fish Springs Ranch facility is a 100 MW-AC solar PV also located in Washoe County, Nevada. The project incorporates 25 MW of battery storage. The solar farm is projected to declare commercial operation in December 2021. The project was approved by the Commission in Docket No. 18-06003. When the solar farm achieves commercial operation, the energy and renewable credits produced will be split between Nevada Power (60 percent) and Sierra (40 percent). The PPA is for 25 years.

13. Nevada Solar One Project
    The Nevada Solar One facility is a 69 MW concentrating 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 PPAs with the facility expire on December 31, 2027.

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

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

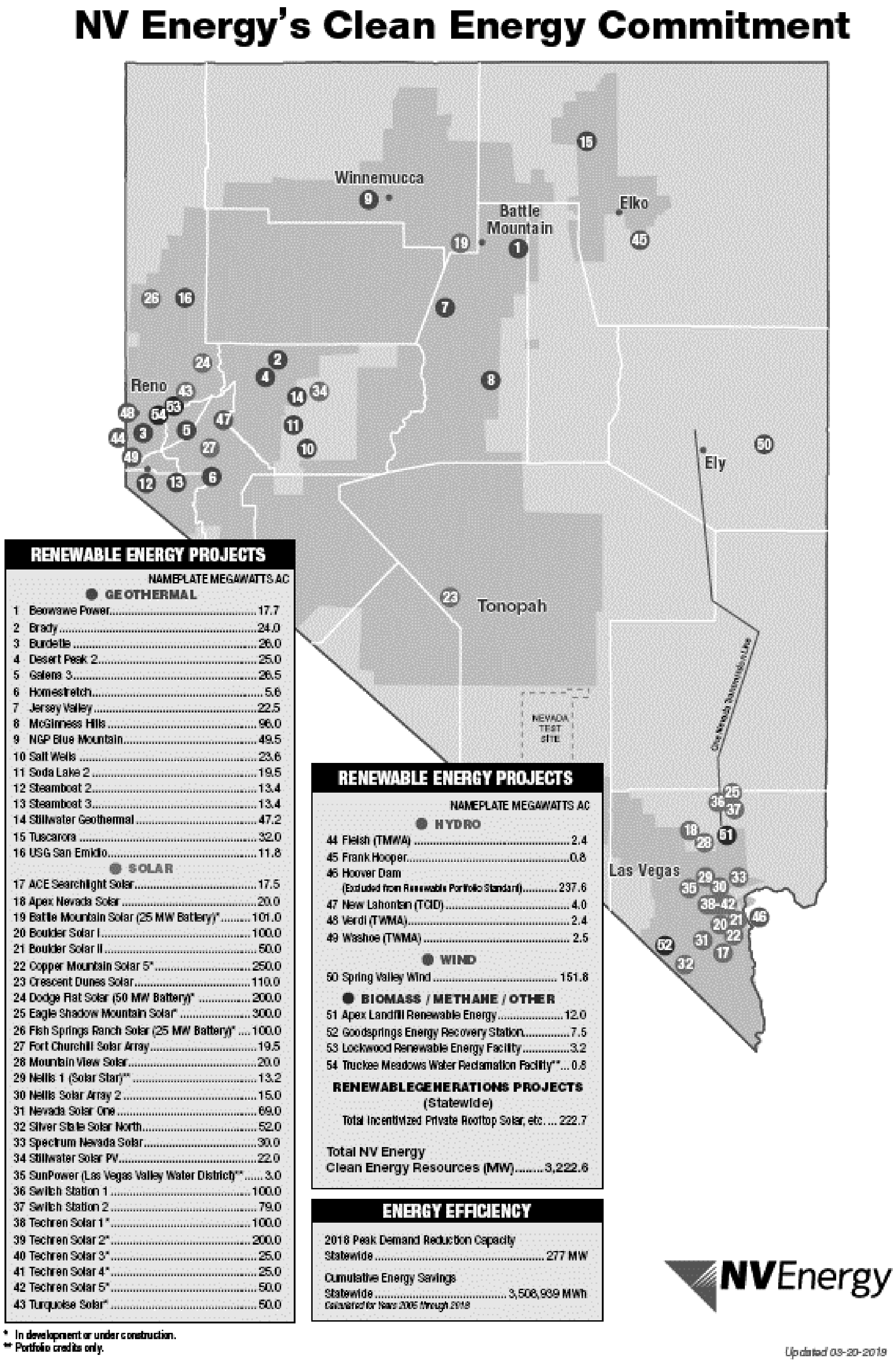
16. <u>Verdi Hydro Project</u>
The Verdi facility is a 2.4 MW hydro-electric project located in Washoe County, Nevada. The hydro facility is owned by the Truckee Meadows Water Authority and went into service in 2009. Sierra has a 20 year contract with the facility that expires on June 1, 2029.

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

18. <u>Truckee Meadows Waste Water Facility ("TMWWF") Project</u>
The TMWWF facility is 0.8 MW biogas facility where Sierra has a PC only purchase agreement. The agreement was approved by the Commission in 2006. The 20-year contract expires on December 12, 2024.

Figure SS-1 below is a map showing all renewable facilities contracted to Nevada Power and Sierra. The map includes Hoover 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 towards meeting the RPS.

FIGURE SS-1 NV ENERGY RENEWABLE ENERGY MAP



COMPLIANCE OUTLOOK

Nevada Power and Sierra both exceeded the 2018 RPS of 20 percent. Nevada's RPS is a credit requirement that is calculated based on total retail megawatt hourly sales. The RPS requirements and rules were revised in April 2019 with the Governor signing into law Senate Bill 358 ("SB 358"). Under SB 358, the RPS will increase to 22 percent in 2020, 24 percent in 2021, 29 percent in 2022, 34 percent in 2024, and 42 percent in 2027, before rising to 50 percent starting in 2030 and beyond. The RPS no longer contains a solar carve out, which had required that a minimum of six percent of the overall credit requirement be met with renewable energy credits from solar resources. SB 358 now permits utilities to exclude from the RPS calculation retail sales that are covered under a green energy tariff pursuant to NRS § 704.738. SB 358 also expanded resource eligibility by permitting the use of credits from large hydro facilities such as Hoover to now count towards compliance.

While the most significate change in SB 358 was the doubling of the standard from 25 to 50 percent, the bill left in place several rules that allow utilities to meet their annual credit requirement through the use of credit multipliers, station usage credits, and demand side management credits. The use of these non-net energy renewable credits will, however, eventually go away. Station usage and multiplier credits are restricted to generating units placed in to service on or before December 31, 2015, and the use of demand side credits is being phased out and will completely go away starting in 2025.[10]

Nevada Power

While Nevada Power's compliance outlook at this time can best be summarized as positive, there are still risks that could shift this outlook. There is the risk that an operating project will fail to meet its contractual supply commitment. A prime example of this risk is Tonopah Crescent Dunes. Tonopah Crescent Dunes is a large, 110 MW AC, solar thermal generator that was expected to deliver in excess of 500,000 kPCs annually. Since declaring commercial operation in late 2015, the plant has experienced frequent and prolonged outages. The current outlook reduces the expected amount of energy and credits from this plant by 50 percent in 2019 and 25 percent in 2020 and beyond. Given the size of the project, Nevada Power simply does not have enough credit reserves nor sufficient new renewable capacity in the pipeline to overcome lasting, multi-year credit shortfalls. Although, Nevada Power is currently positioned to meet its future credit commitments (RPS, NGR, Sierra PC-pool repayments, and NRS Chapter 704B obligations), experience has shown that renewable projects, both operating and pipeline, can be unpredictable. Even if Tonopah Crescent Dunes is able to resolve all of its operating issues, issues could arise with another renewable resource whereby lost credits must be replenished. Finally, there is the risk that one or more of the pipeline projects are delayed or, worse, cancelled. In order to meet the higher credit requirement and to achieve the Company's own renewable goals, new projects must achieve their operating date targets. The credits lost due to start up delays cannot be easily or quickly replaced, if at all.

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

Sierra

Sierra's outlook is cautious. Unlike Nevada Power, which currently only has a very small number of NGR customers, the ability of Sierra to now exclude NGR sales from the RPS calculation reduces its overall credit requirement by over 240,000 kPCs. This adjustment provides Sierra just enough cushion to absorb the initial uptick in the RPS in 2022 to 29 percent until the 1,001 MW of new solar generation becomes operational. Like Nevada Power, increases to RPS will require Sierra to add new resources. The Sierra outlook is not without risk. With the economic growth in the north, Sierra could face load surprises; one or more of the six projects recently approved by the Commission could be delayed or, worse, cancelled, and finally, one or more of its current operating projects could begin to fall short on its supply commitment or be terminated early.

Both utilities now face a 50 percent RPS by 2030. While some of the recently enacted changes to the RPS, such as the ability to exclude NGR sales from total retail sales in calculating the credit requirement and the ability to count generation from large hydro plants, such as Hoover, help, these changes, even with the recently approved 1,001 MW of new generation, are not enough. Both utilities must continue to strategically add new renewable generating resources, or both could quickly become non-compliant. Because of the timeline, initial approval to operation, a new project approved in 2019 will most likely not deliver significant quantities of green energy until 2023 or early 2024, and, by then, the RPS will have risen from 20 percent to 34 percent.

2. 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 of the changes in SB 358. In determining future PC needs, the Companies must carefully consider one overarching objective:

- Full compliance with an escalating and compressed RPS schedule: 22 percent by 2020, 24 percent by 2021, 29 percent by 2022, 34 percent by 2024, 42 percent by 2027, and 50 percent by 2030.

For this Amendment, the Companies developed renewable expansion plans under various scenarios. All expansion plans assume full compliance with an escalating RPS based on the forecasted load projection. The annual RPS credit requirements were calculated in compliance with NRS § 704.7821 as revised by SB358 as enrolled, which sets forth the annual PC requirement for the Companies based on a percentage of total electricity sold to their retail customers during a calendar year. The expected PC supply was determined starting with the current portfolio of approved projects, both operating and under development or contemplated by the Companies.

Several assumptions are built into the forecast.

- Existing contracts expire in accordance with the contract terms and are not automatically renewed;[11]
- The Companies adjust the expected amount of energy and credit from renewable facilities for the period of 2019-2022 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 its annual energy supply plans. This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-terms plans;

- Credits from the Renewable Generations incentive programs will continue until funds are exhausted and/or the programs expire in 2021, and solar systems placed into service after 2015 do not qualify for the solar multiplier. The plan assumes that the number of credits for Renewable Generations will plateau in 2020 and then remain flat;

- The plan assumes that the percent of annual credit contribution from energy efficiency and conservation measures would be limited to no more than 20 percent of the credit total in 2019, decreasing to no more than 10 percent of the total in 2020, and finally 0 percent of the total starting in 2025;

- Surplus credits are carried forward without limitation, the plan assumes no surplus PC sales;

- The plan contemplates that Nevada Power will continue to repay its credit obligation to Sierra, with all credits fully repaid by 2021 (which is before Sierra would have a need to add a new project);[12]

- The plan assumes that generation from both Company-owned photovoltaic systems and PPA projects would be degraded starting the year following the first full year of operation;

- Geothermal projects and placeholders would continue to qualify for station usage credits; all other technologies would no longer qualify;

- The plan accounts for all Commission-approved NGR agreements as of April 2019 where PCs associated with all or a portion of the output from a renewable facility(s) have been assigned to a customer under the NGR tariff, and therefore cannot be used by the Companies in meeting their RPS credit requirements;

- The plan assumes the ability to exclude NGR sales from retail sales in the RPS calculation;

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

[12] The repayment over a three year period is a modeling protocol in the renewable planning process but is not intended to reflect how and when actual repayments would be made since such amounts would depend on the factual circumstances that will occur during this time period (*e.g.*, load, renewable generation, changes in law, etc.).

- The plan assumes that the energy produced by Hoover and allocated to Nevada Power counts towards meeting the RPS;
- The plan assumes no further changes to the existing statutory and regulatory regime beyond those currently enacted under SB 358; and
- The preferred plan assumes the approval of the three new PPAs with the energy and credits to be divided between the two utilities.[13]

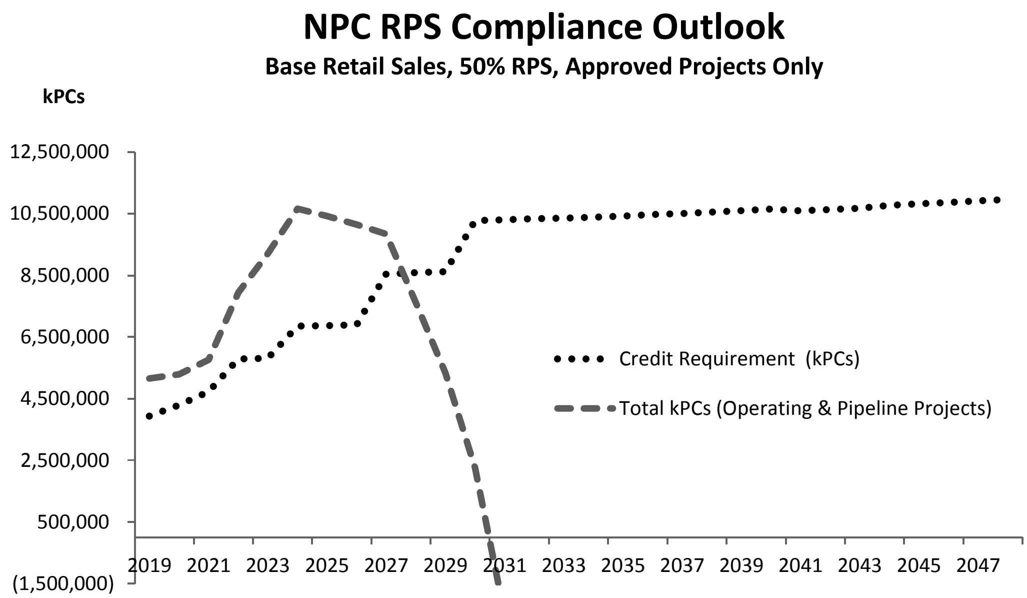
As in the past plans, generic placeholders were added to address future RPS requirements not yet met through existing contracts and proposed contracts. Because all placeholders occur after the current Action Plan period, as in past plans, placeholders do not imply the Companies' intentions to develop these projects. The Companies would undertake a request for proposals to determine the best option to meet the RPS when new resources are needed. Thus, the underlying assumption can be revisited if other more economical options are presented at that time. Placeholder pricing was set based on fall 2018 renewable energy request for proposals ("Fall 2018 RE RFP" or "RFP") bids. Pricing for both geothermal and solar PV placeholder projects were adjusted by 2 percent annually to account for inflation. Solar PV prices were also adjusted starting in 2024 to reflect the phasing out of the solar Investment Tax Credit ("ITC"). The ITC is scheduled to drop to 26 percent in 2020, 22 percent in 2021 and finally 10 percent in 2022.

After developing the renewable baseline forecast, the Companies added placeholder projects that would ensure both Companies meet the RPS, taking into account replacement of renewable energy expected to be lost due to expiring contracts. The renewable expansion plans were all developed assuming full compliance throughout the 30-year planning horizon.

The following figures illustrate the RPS compliance projections for Nevada Power and Sierra. The first set of charts assumes that no action is taken to add new renewable resources. Both figures are based on each Company's current renewable portfolio and above planning protocol under a base load projection. PCs deficits are rolled over to the following year and are not forgiven.

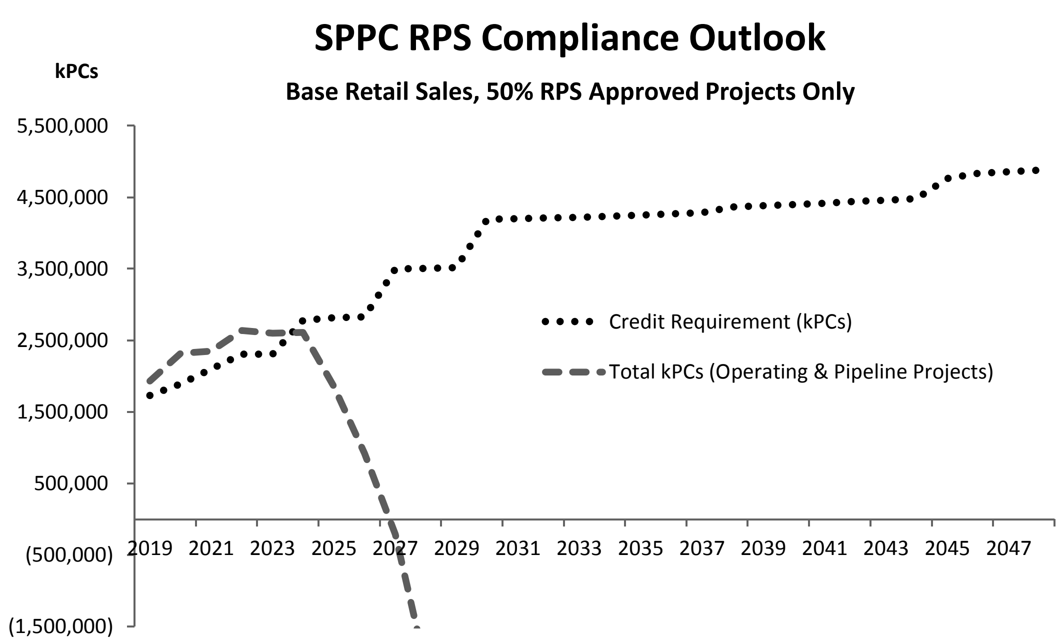
[13] Moapa: 30% to Nevada Power and 70% to Sierra; Southern Bighorn: 60% to Nevada Power and 40% to Sierra; and Gemini: 100% to Nevada Power.

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



Based on the above, Nevada Power is projected to be RPS non-compliant in 2028.

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



Based on the above, Sierra is projected to be RPS non-compliant in 2024.

The figures below show Nevada Power's and Sierra's respective RPS compliance outlooks assuming the approval of the three PPAs. The figures also assume that the energy and credits produced by two of the three projects would be divided between the two utilities to the benefit of both. The initial surge in total number of kPCs available to meet the RPS requirement, solid black line on the charts below, is due to credit banking. As discussed above, both plans assume that all excess PCs are banked, not sold, and both assume unlimited banking. The plans also assume that the Companies will replace expiring renewable contracts throughout the planning horizon in order to maintain renewable capacity. With the three new projects, NPC is projected to be RPS non-compliant in 2035 and Sierra with the two new projects is projected to be RPS non-compliant in 2028.[14]

[14] Please refer to REN-4 for buildout details

FIGURE SS-4 NEVADA POWER'S RPS OUTLOOK
GEMINI, MOAPA & SOUTHERN BIGHORN SOLAR

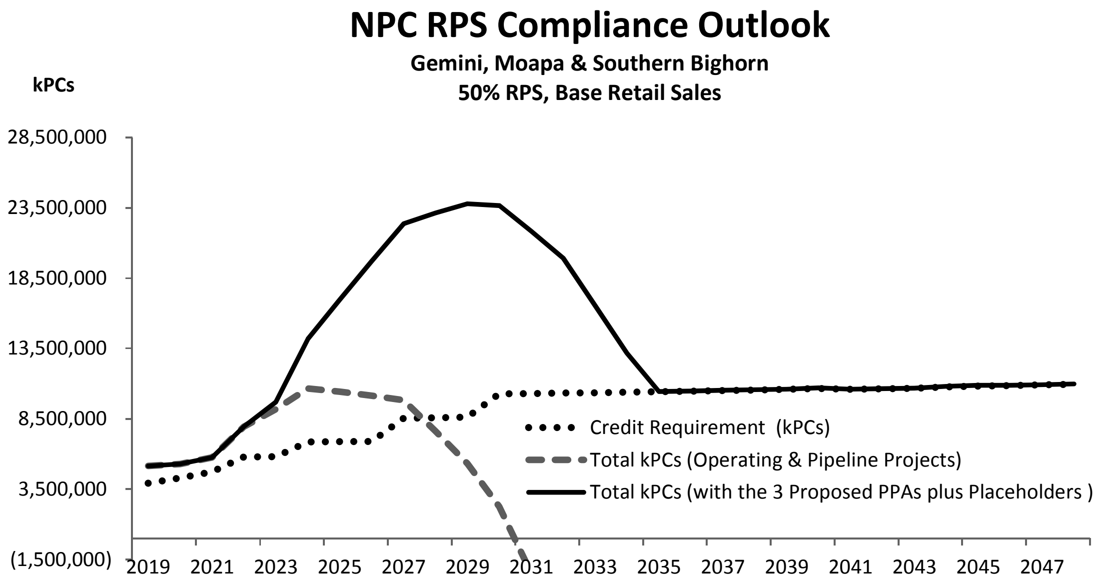
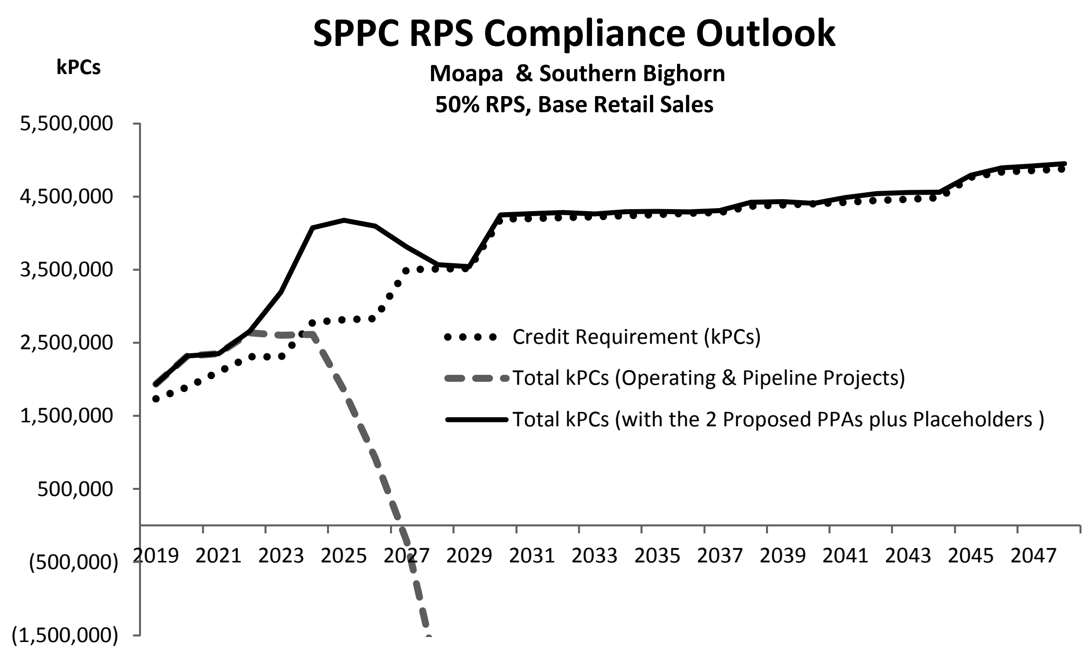


FIGURE SS-5 SIERRA'S RPS OUTLOOK
MOAPA & SOUTHERN BIGHORN SOLAR



In addition to the above, the Companies also modeled three alternative outlooks. One assumed just the approval of Gemini, another just the approval of Southern Bighorn Solar, and the third, just the approval of Moapa. The results of the alternative outlooks are shown below.[15]

[15] Please refer to REN-4 for the buildout details

FIGURE SS-6 NEVADA POWER'S RPS OUTLOOK
GEMINI SOLAR ONLY

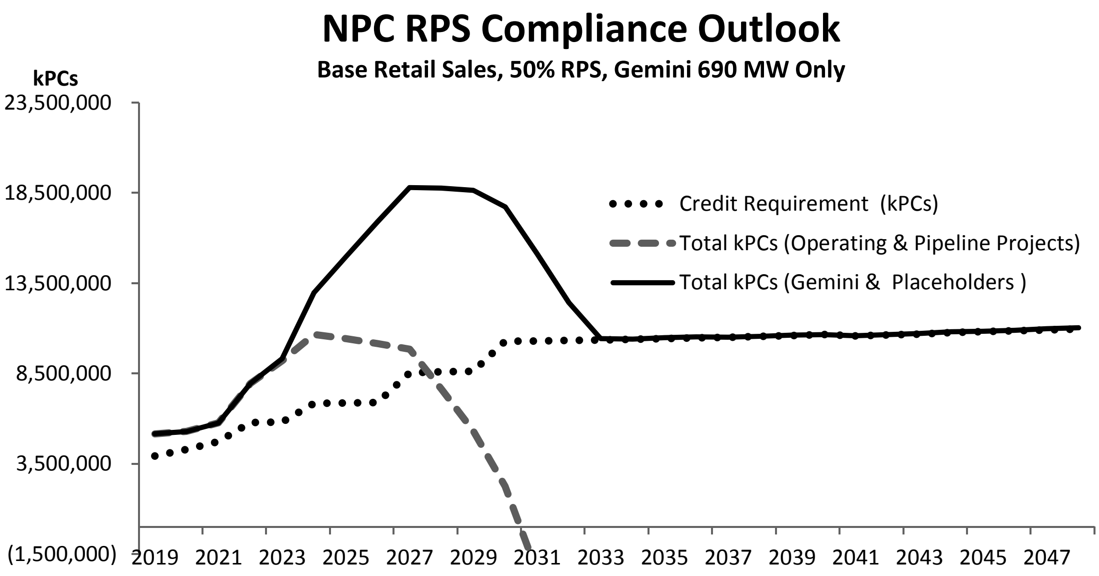


FIGURE SS-7 SIERRA'S RPS OUTLOOK
GEMINI SOLAR ONLY

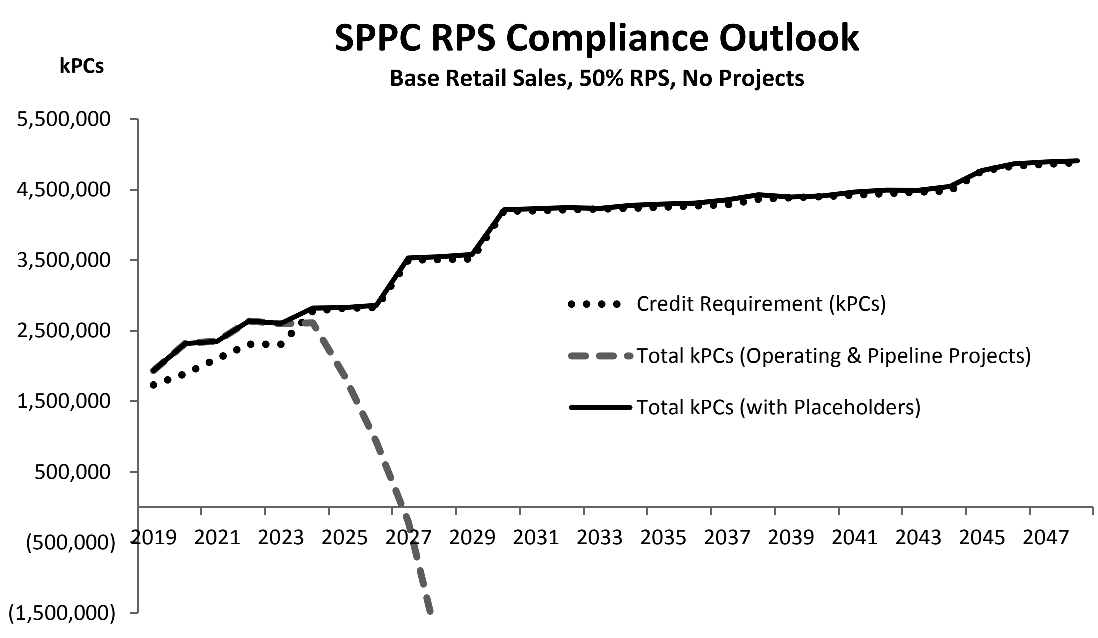


FIGURE SS-8 NEVADA POWER'S RPS OUTLOOK SOUTHERN BIGHORN SOLAR ONLY

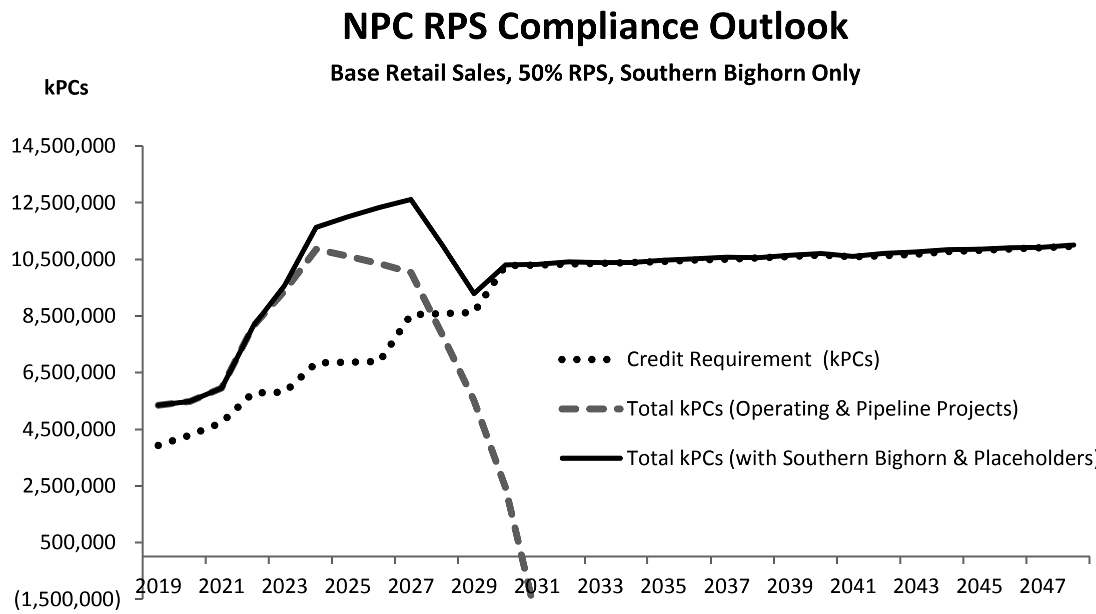


FIGURE SS-9 SIERRA RPS OUTLOOK SOUTHERN BIGHORN SOLAR ONLY

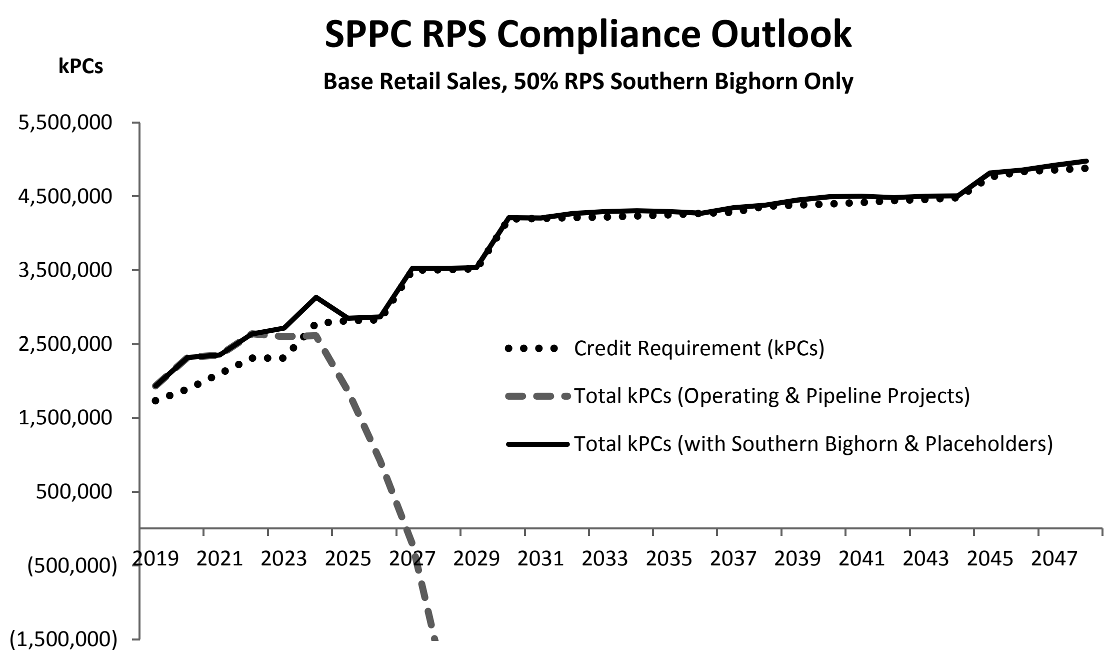


FIGURE SS-10 NEVADA POWER'S RPS OUTLOOK
MOAPA SOLAR ONLY

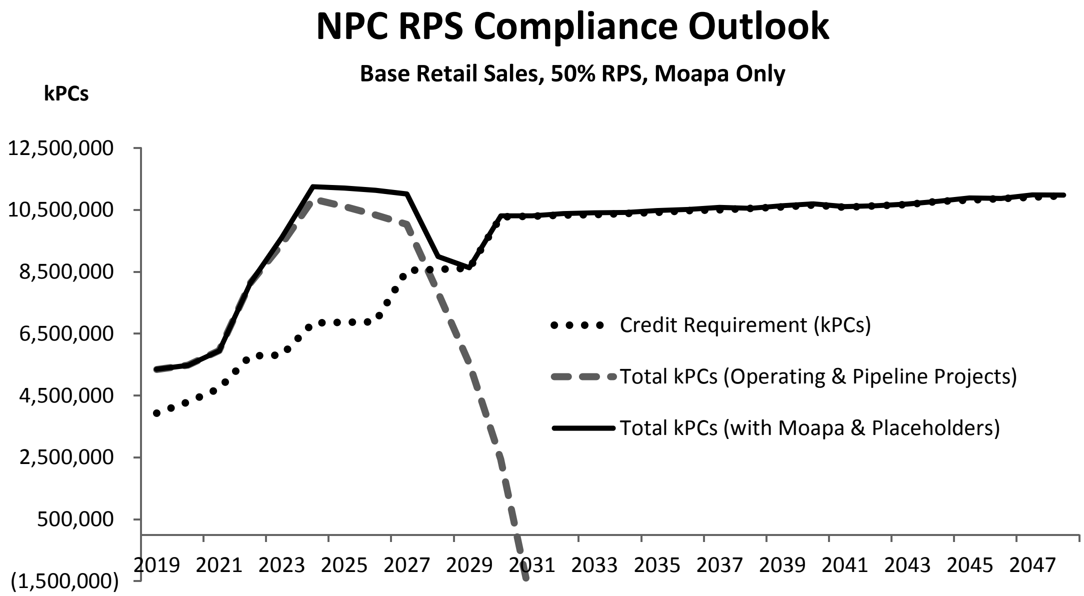
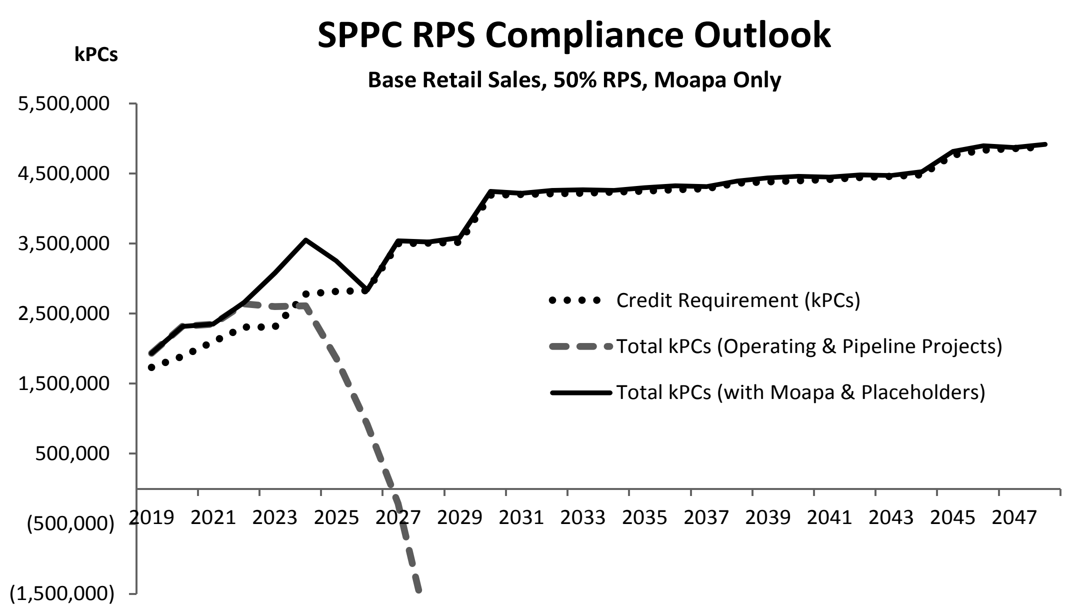


FIGURE SS-11 SIERRA'S RPS OUTLOOK
MOAPA SOLAR ONLY



Nevada Power and Sierra will continue to closely monitor its RPS compliance outlook recognizing that there are a myriad of factors, some outside of the Companies' control, which ultimately determine whether the Companies will have a sufficient number of PCs to satisfy their RPS credit obligation. The objective is to never be put into a reactive position where the Companies must acquire a large number of PCs in a short time frame in order to maintain compliance. Time expands options which in turn increases the ability of the Companies to negotiate favorable contracts to acquire renewable generating resources to meet the needs of their customers and to meet or exceed all regulatory and internal requirements.

Technical Appendixes REN-1 through REN-4 contain the placeholder profiles and placeholder pricing that were used to develop the above outlooks. The appendices also contains the 12x24 supply tables, and degradation for the three proposed projects as well as tables showing the projected RPS credit requirement and a breakdown of total PCs and placeholder projects by year for the above charts.

3. Joint Fall 2018 Renewable Rfp

Sierra and Nevada Power issued the Fall 2018 RE RFP on October 16, 2018, with the intent of the Companies securing proposals for the acquisition of long-term dispatchable renewable energy resources, together with all associated environmental and renewable energy attributes. The timing of the RFP was driven by the imminent step-down of the federal Investment Tax Credit from 30 percent in 2019 to 26 percent in 2020. The RFP was renewable technology agnostic and included a request for optional battery energy storage systems ("battery storage").

The Companies have reached a point where they can be selective in choosing projects that not only meet future energy needs but also meet those needs at competitive prices. All of the Companies' renewable projects, both PPA and company-owned, are located in Nevada,[16] and are currently delivering renewable energy to meet the needs of the Companies' customers. In this filing, the Companies are requesting Commission approval to enter into three new PPAs for Nevada Power totaling 1,190 MW. The three PPAs are modeled in the M_S_A Case. Approval of these PPAs is a significant step in helping the Companies maintain compliance with an increasing renewable portfolio standard and in achieving the goal of matching one-hundred percent of customer demand with renewable generation. The addition of these dispatchable and cost-effective renewable energy projects, which include 590 MW of battery storage with 2,331 MWh[17] of energy delivery capability, is consistent with the Companies' strategy of delivering energy and services that customers value at low and reasonable rates. The addition of these resources furthers the transformation of the Companies' energy supply portfolio, reducing both carbon emissions and fuel price risk. Finally, as noted above in the introduction and below in the discussion about the selection of the Preferred Plan, the Preferred Plan positions the Companies to meet the needs of customers, including the needs of large commercial and industrial customers.

Similar to the approach set forth in the Emissions Reduction and Capacity Replacement plan, the Companies prepared and completed the Fall 2018 RE RFP for new renewable energy projects in

[16] Securing projects located within Nevada brings jobs and economic benefits to the state.
[17] Cumulative over an approximate four-hour period (i.e. Full Requirements Period, as specified in PPAs).

Nevada. The Companies developed and implemented a process for this RFP consistent with guidance previously provided by the Staff.

a. JOINT FALL 2018 RE RFP BID PROTOCOL

The Companies prepared a bid protocol ("Protocol") describing the purpose of the Fall 2018 RE RFP, the process by which the Fall 2018 RE RFP would be conducted, the schedule, a description of the information required for each bid, bid submittal instructions, minimum eligibility requirements, and a description of the evaluation process. Bidders were instructed to review and propose changes to the Companies' pro forma PPA, as well as a Build Transfer Agreement ("BTA"), an Asset Purchase Agreement ("APA") and associated Engineering, Procurement and Construction ("EPC") agreement, the pro-forma documents.

The Protocol required bidders to register in the PowerAdvocate system, a web-enabled tool used by the Companies' procurement group to manage competitive bidding processes. Bidders that registered in PowerAdvocate were provided the bid Protocol along with all the other documents and information necessary to prepare and submit their proposals.

All communication with bidders, up to commencement of negotiations, was conducted through PowerAdvocate. Using PowerAdvocate, bidders were able to submit questions to the Companies who then responded to all bidders through PowerAdvocate. Bids were required to be submitted using the PowerAdvocate tool.

A bid fee was required for each bid submittal; $10,000 per project/proposal, including: 1) in the case of a PPA, 15 and 25 year terms, each with up to two pricing options (e.g. escalating price, fixed price, etc.), so long as the proposed product was the same (e.g. with storage or without storage) and a related build-transfer agreement option; and 2) in the case of storage-only bids associated with an existing PPA with the Companies, 15 and 20 year terms, each with up to two pricing options (e.g. escalating price, fixed price, etc.). Up to two additional pricing variations could be proposed for an additional $2,500 fee each. A total of $612,500 in fees was collected, $502,500 of which was retained by the Company, with the balance of $110,000 being returned to disqualified or overpaid bidders. The retained bid fees were used to help cover the cost of the Independent Evaluator ("IE") and other external consulting costs.

b. INDEPENDENT EVALUATOR

The Companies utilized the services of an IE for the Fall 2018 RE RFP. The IE oversaw the Fall 2018 RE RFP to ensure a competitive, fair and transparent RFP process was conducted. Use of the IE for this Fall 2018 RE RFP event was not required, however, in light of the parallel effort to bring forward a company-owned project, the IE provided an additional level of oversight to ensure that the RFP process was not influenced by the efforts of the Companies to select their own project. The IE, among other things, validated that the Fall 2018 RE RFP evaluation criteria, methods, models and other processes were consistently and appropriately applied to all bids and that the assumptions, inputs, outputs and results were appropriate and reasonable. The IE independently scored the bids to determine whether the Companies' initial or final selections were reasonable, and oversaw negotiations. The IE report of findings is contained in Confidential Technical Appendix REN-9.

c. 2018 Request for Proposals

The Fall 2018 RE RFP was issued on October 16, 2018. The Protocol document informed interested parties that the Companies were seeking to acquire long-term renewable energy resources, and their associated environmental and renewable energy attributes, ranging from 20 MW and up in capacity. The Fall 2018 RE RFP specified project commercial operation dates no later than December 31, 2023. The Companies requested proposals from projects that qualified as renewable energy resources as defined under NRS §§ 704.7315, 704.7811 and 704.7815, and pursuant to NAC §§ 704.8831 through 704.8893, including, but not limited to, solar, geothermal, wind, and biomass. The Companies also stated that while the Fall 2018 RE RFP was not renewable technology specific, they would not consider demand-side, energy efficiency, or Nevada portfolio energy credit-only proposals. In addition to renewable energy resources, the Companies stated they would consider supplemental battery storage associated with existing renewable energy resources under contract with the Companies that are eligible for the ITC. The Companies specified that certain product types be dispatchable by the Companies' system operator.

Acceptable ownership structures for long-term renewable energy resources included PPAs, APAs for certain existing renewable energy resources, and BTAs. PPAs for renewable energy resources were required to be for 15 years or 25 years in length, and include purchase options that would allow NV Energy to purchase the renewable energy resource, including all energy, capacity and associated environmental and renewable energy attributes, at periodic intervals following the commercial operation date of the renewable energy resource, including at the end of the term. Addition of battery storage to existing PPAs was required to have a term of 15 or 20 years not to exceed the remaining term of the existing PPA. APAs for the sale of existing renewable energy resources would be considered as long as the resource was not currently under contract with the Companies. Any BTAs would also be considered, subject to the Companies' EPC standards.

Scoring criteria for proposals set out by the Companies in the Protocol document included: (a) the greatest economic benefit to the State of Nevada, (b) the greatest opportunity for the creation of new jobs in the State of Nevada, (c) the best value to the Companies' customers; and, (d) the financial stability of the bidder and the ability of the bidder to financially back the proposal and any warranties and production guarantees.

The Protocol document required projects to have a point of delivery already identified and connect directly to the Companies' transmission system. The Protocol and attachments are included in Technical Appendix REN-5.

Proposals were received December 17, 2018. The Companies received 145 conforming bids from 18 counter-parties, covering 31 project sites, totaling more than 5,500 MW of nameplate renewable energy resource capacity and 2,800 MW of supplemental battery energy storage. The vast majority of projects were for solar PV technology. One proposal was submitted for concentrated solar power, one for bio-power and three geothermal facilities were proposed. Of the proposals involving solar technology, most included options for co-located battery storage systems. Battery storage systems were also proposed to be added to three existing renewable PPAs.

Table REN-1 provides a summary of the bid options allowed under the RFP and the number of conforming bids received for each option in response to the RFP.

TABLE REN-1
CONFORMING PROPOSALS RECEIVED FOR Fall 2018 Renewable RFP

Product	Category:	A	B	C
	Bid Option	Renewable [1]	Renewable + Storage [1]	Storage Only [2]
	Existing Generating Facility: [3]			
1	PPA	X		
2	APA [4, 7]	X		
	New Storage at Existing NVE Contracted Renewable Energy Project: [6]			
3	PPA [8, 10]			X
4	BTA [5, 8]			
	New Project:			
5	PPA [8, 9]	X	X	
6	BTA [4, 5, 7, 8]	X	X	

d. INITIAL EVALUATION PROCESS.

In the initial evaluation phase, bids were ranked based on a combination of three criteria: price, non-price and economic benefits to the State of Nevada.

Price was measured by calculating the levelized cost of energy ("LCOE") over the term of the proposed PPA. The LCOE included projected energy payments under the PPA as well as the estimated cost of network upgrades for the proposed project. The LCOE accounted for any escalation of the bid price, as well as any degradation in energy deliveries over the term of the PPA, as indicated by the bidder in their bid submittal. The price score was given a 60 percent weight.

The non-price scoring was based on four categories: (1) the bidder's project development experience, (2) the technology of the project, (3) conformity to the pro-forma PPA and (4) project development milestones. The non-price score was given a 30 percent weight.

For the bidder's project development experience, the Companies evaluated the bidder's (a) project development experience, (b) Nevada, federal or tribal lands development experience, (c) ownership/operation and maintenance ("O&M") experience, (d) Occupational Safety and Health Administration recordable incident rate, and (e) financial capability. The bidder's project development experience accounted for 25 percent of the non-price score.

For technology of the project, the Companies evaluated the bidders' (a) technical feasibility, (b) resource quality, (c) bidder's equipment supply control, (d) utilization of the resource, (e) flexibility, (f) environmental benefits, (g) fuel diversity/hedging, and (h) other ancillary services. Technology of the projects accounted for 25 percent of the non-price score.

For conformity to the proforma agreements, the Companies evaluated the magnitude of the bidder's proposed edits to the proforma agreements. Conformity to the proforma agreements accounted for 25 percent of the non-price score.

For project development milestones, the Companies evaluated (a) land and environmental authorization status/feasibility, (b) water rights, (c) project financing status, (d) interconnection progress, (e) transmission requirements and (f) reasonableness of critical path dates. Project development milestones accounted for 25 percent of the non-price score.

The economic benefit to State of Nevada scoring was based on three categories: (1) location of jobs relative to the off-taking company (i.e., Sierra or Nevada Power); (2) number of jobs created during construction and for ongoing operation of the project; and (3) value of direct expenditures of the project in Nevada. The economic benefits score was given a 10 percent weight.

Based on the resulting weighted scores of the bids, initial shortlists for each resource type (i.e. solar, solar + storage, bio-power, etc.) were developed. Bidders selected for the Fall 2018 RE RFP initial shortlist were notified on February 5, 2019. Shortlisted bidders were permitted to submit "best and final" pricing by February 8, 2019. The initial shortlist selections were reviewed with the IE and the IE concurred with the Companies' selection.

e. PWRR ANALYSIS.

Several bids from the initial shortlist in the Fall 2018 RE RFP were evaluated using the Companies' present worth of revenue requirement ("PWRR") analysis and capital expense recovery model ("CER") to determine the potential revenue impacts that the bid would have on the Companies' customers.

Table REN-2 shows the PWRR results of the projects for which the Companies seek approval. Additional projection costs and the PWRR are found in confidential Technical Appendix REN-9.

TABLE REN-2
RENEWABLE PPA PWRR RESULTS

	10 Year PWRR 2018-2027 (million $)	20 Year PWRR 2018-2037 (million $)	30 Year PWRR 2018-2047 (million $)	20 Year PWRR Rank	30 Year PWRR Rank
ESM2 - 25yr	$ 10,752	$ 18,321	$ 24,198	4	1
ESM2 - 25yr+BESS	$ 10,757	$ 18,319	$ 24,199	3	2
Arevia 440 - 25yr+BESS	$ 10,738	$ 18,297	$ 24,216	2	3
Moapa - 25yr+BESS	$ 10,772	$ 18,357	$ 24,233	7	4
Arevia 690 - 25yr+BESS	$ 10,738	$ 18,255	$ 24,234	1	5

Key Result Findings. The following are the key results findings of the best and final PWRR analysis:

- The Arevia project, due to its scale and favorable pricing showed the largest benefit to customers at the 20-year point.
- The 8minutenergy 25-year project (ESM2), now known as Southern Bighorn Solar, with and without storage, have nearly identical PWRRs at both the 20-year and 30-year outlooks.

f. ADDITIONAL ANALYSIS OF SHORTLISTED BIDS

Additional due diligence was conducted on the shortlisted bids. The due diligence included: (1) status and timing of interconnection, (2) site control, (3) status of material permits, (4) solar panels, (5) other material equipment, (6) delivery profile, (7) milestone schedule, (8) material exceptions to the pro-forma PPA, (9) development and operating experience, (10) financial capability, (11) safety, (12) water supply, and (13) project labor agreement. Burns & McDonnell was retained to evaluate items (4), (5), (6), (7) and (9) and internal subject matter experts evaluated the remaining items. Based on this analysis, the top bidders for negotiations were selected. No fatal flaws were identified with any of the shortlisted bids.

g. FINAL SELECTION

EDF and 8minutergy were notified of being on the final shortlist on February 18, 2019. Arevia was added to the final shortlist on April 22, 2019. The three projects proposed in this filing were selected from the initial shortlisted counterparties.[18] All three will utilize solar PV panels with single axis trackers, have dispatchable capability, and include battery storage charged by the co-located solar renewable resource.

EDF's Moapa Solar project is a proposed 200 MW capacity solar facility with an associated 75 MW, 375 MWh battery system located in Nevada Power's service territory, with an anticipated

[18] A bidder with a project in Sierra's territory was added to the final shortlist on February 23, 2019, however, the parties were unable to reach mutually agreeable contract terms and negotiations were terminated on March 15, 2019.

commercial operation date ("COD") of December 1, 2022. The solar component of Moapa Solar will contribute to fulfilling the Companies' RPS compliance obligation.

8minutenergy's Southern Bighorn Solar project is a proposed 300 MW capacity solar facility with a 135 MW, 540 MWh battery system. It is located in Nevada Power's service territory on the Moapa River Indian Reservation. It has an anticipated COD of September 1, 2023. The solar component of Southern Bighorn Solar will contribute to fulfilling the Companies' RPS compliance obligation.

Arevia's Gemini Solar project is a proposed 690 MW capacity solar facility with an associated 380 MW, 1,416 MWh battery system located in NPC's service territory, with an anticipated COD of December 1, 2023. The solar component of Gemini Solar will contribute to fulfilling Nevada Powers' RPS compliance obligation.

Once again, project scoring, ranking and selection were reviewed with the IE, and once again, the IE concurred with the Companies' selections. The Companies' documentation of the final analysis and selections is contained in Confidential Technical Appendix REN-8.

The Companies successfully completed negotiations with EDF and 8minutenergy and executed the agreements on March 27, 2019. The Companies successfully completed negotiations with Arevia and executed the agreement on May 1, 2019.

4. Approval Of Three New Renewable Ppas

Three PPAs are being submitted to the Commission for approval. PPA pricing is per megawatt-hour rate, which includes the battery storage. These supply additions, described in more detail below, support continued compliance with the RPS, contribute to managing the open position, provide dispatchability (i.e. generator control), enhance fuel diversity, and leverage the reactive power capabilities of solar PV and energy storage inverters to provide voltage support and other grid support services. With these projects, the Companies lock in a substantial level of renewable energy supply at the current market's attractive pricing before the 30 percent ITC expires, for the long-term benefit of its customers.

The three PPAs and their battery storage systems are incorporated into the M_S_A Case. The M_S_A Case has been selected as the Companies' preferred plan.

The Companies request that the Commission's order reflect the statutory consequence of such a finding; namely, that the PPA contracts and their terms shall be deemed to be prudent investments and the utility provider may recover all just and reasonable costs associated with the contracts pursuant to NRS § 704.7821(2)(c)(2). Table REN-3 summarizes the new contracts completed and filed for Commission approval in this filing.

TABLE REN-3
NEW CONTRACTS

Counterparty	Agreement Type	Technology	Capacity	Expected Commercial Operation	LCOE [$/MWh]
8minutenergy Southern Bighorn Solar Farm	25 year PPA	PV with battery storage	300 MW 135 MW Battery Storage	09/01/2023	$ 36.86
EDF Renewables Moapa Solar	25 year PPA	PV with battery storage	200 MW 75 MW Battery Storage	12/1/2022	$36.79
Arevia Gemini Solar	25 year PPA	PV with battery storage	690 MW 380 MW Battery Storage	12/1/2023	$42.83

a. MOAPA SOLAR 200 MW SOLAR WITH 75 MW BATTERY STORAGE PPA (NEVADA POWER)

The proposed Moapa Solar project is to be developed by EDF under the special entity Arrow Canyon Solar, LLC located within the Moapa River Indian Reservation in Clark County, Nevada. Arrow Canyon Solar, LLC is wholly-owned by EDF Renewables ("EDFR") North America, which is part of the EDF ownership structure. EDFR is a market leading independent power producer and service provider with more than 30 years of expertise in renewable energy. EDFR delivers grid-scale power: wind (onshore and offshore), solar PV and storage projects; distributed solutions: solar, solar plus storage, EV charging and energy management; and asset optimization: technical, operational, and commercial skills to maximize performance of generating projects. EDF Renewables' North American portfolio consists of 10 GW of developed projects and 10 GW under service contracts. EDFR is a subsidiary of EDF Energies Renewables, the dedicated renewable energy affiliate of the EDF Group. EDF SA is a publicly traded company that is majority owned by the French Government. EDF shares have been listed on Euronext Paris since November 18, 2005 (with first negotiation on November 21, 2005). EDFR is 100 percent owned by EDF SA through its global renewable energy subsidiary EDF Renewables (EDF EN).

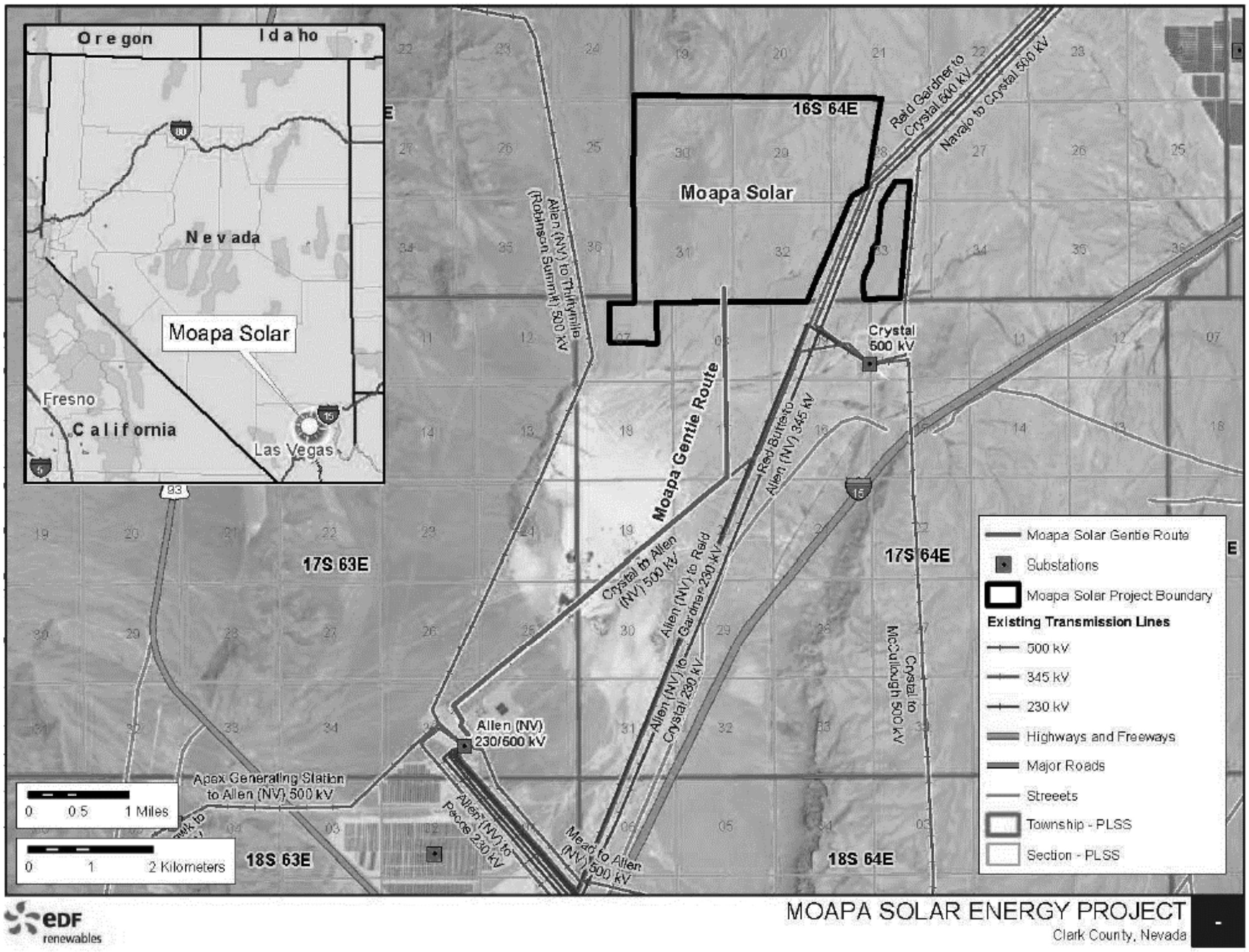
EDFR currently owns and operates 5.2 GW of installed renewable capacity. Although most of the company's development and operating experience is in wind energy, the company states that it has developed and owns an interest in more than 500 MW of solar PV projects.

The Moapa Solar project will consist of a 200 MW solar PV facility with a horizontal single-axis tracking mounting system. The project is sited on the Moapa River Indian Reservation, approximately 25 miles northeast of Las Vegas, Nevada. The Moapa Solar project expects to utilize Canadian Solar 415W bifacial multi-crystalline PV modules, mounted on various tracking systems with Power Electronics inverters. The DC energy generated by the panels will be wired to combiner boxes, then either to inverters which convert the DC energy to AC energy or to DC to DC converters to charge the battery storage. The solar energy and battery discharge energy will be routed through the inverters to a step-up transformer, where, as a dispatchable resource, it will be delivered to the proposed Harry Allen 230 kV substation via a six-mile generation intertie.

EDFR estimates that the Moapa Solar project will provide more than 300 construction jobs over a 1-year construction period. After commercial operation in December, 2022, the facility is expected to provide three permanent jobs with an average annual salary of $81,000, for an estimated annual payroll of $243,000 and a total payroll of $13.3 million over 35 years (life of the project). Overall, based on information provided by EDFR, the Companies estimate that the total investment in Nevada's economy directly associated with the Moapa Solar project will be more than $271 million. A work site agreement, dated March 26, 2019, was successfully executed between EDF Renewables Development, Inc. on behalf of Arrow Canyon Solar, LLC and IBEW Local Union 357 and IBEW Local Union 396.

The PPA is with Nevada Power for a 25-year term at a flat price of $21.26 per MWh for off-peak hours and $138.19 per MWh during peak hours. Peak hours are hours ending 1700 through 2100 in June, July and August, the Full Requirements Period. The project has an expected net capacity rating of 200 MW (ac). It is expected to generate 655,507 MWh and provide 655,507 portfolio credits ("kPCs") in the first year. Annual energy production and credits are projected to degrade at approximately three tenths of one percent per year. The 75 MW, 375 MWh battery is included in the per-MWh pricing above. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. The purchase price for the option, prior to and after end of term, would be at the greater of (i) fair market value and (ii) the values shown in the PPA. A copy of the PPA can be found in Technical Appendix REN-6-MS (a). Figure REN-1 shows a map of the project site.

FIGURE REN-1
MOAPA SOLAR PROJECT SITE



Technical Appendix REN-6-MS (b) contains detailed information about the Moapa Solar project, including the information required by NAC § 704.8885 and NAC § 704.8887.

b. SOUTHERN BIGHORN SOLAR FARM 300 MW SOLAR PPA (NEVADA POWER)

The proposed Southern Bighorn Solar project is to be developed by 8minutenergy Renewables, LLC ("8minutenergy") within the Moapa River Indian Reservation in Clark County, Nevada. 8minutenergy had total assets of approximately $143 million and showed revenues of just over $2 million in 2016. 8minutenergy has received financing for approximately 37 comparable utility scale solar projects within the past three years.

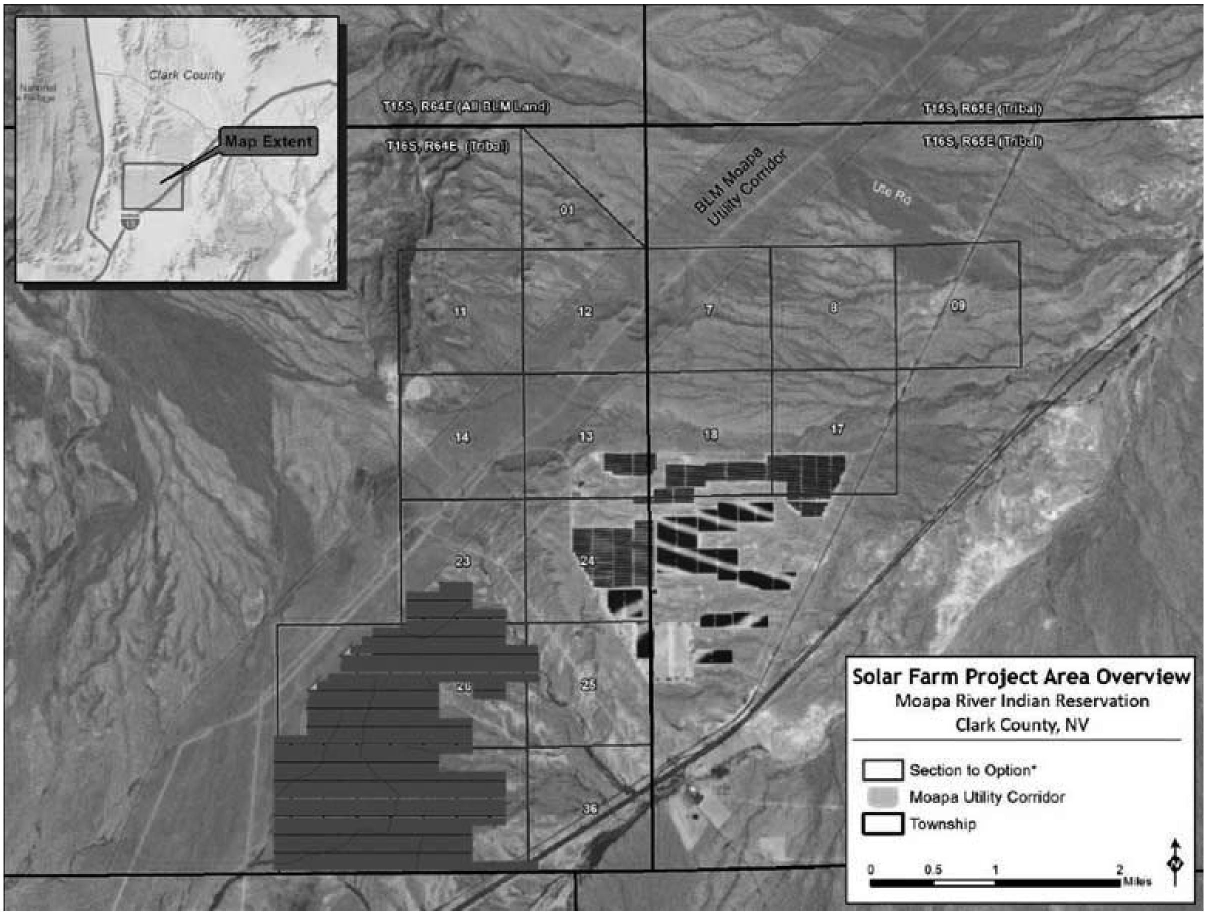
8minutenergy is one of the largest utility scale solar PV and battery storage developers in the United States. Since its inception in 2009, the company has developed and signed PPAs on over 1,800 MW of Solar PV projects. 8minutenergy's current solar and storage development pipeline consists of 7,500 MW of various solar PV development stage projects in addition to 1 GW of battery energy storage in development. Key completed and operating projects in the portfolio include approximately 804 MW in California. 8minutenergy also has over 371 MW of solar projects under construction or construction ready.

The Southern Bighorn Solar Farm ("SBS," formerly Eagle Shadow Mountain 2) will consist of a 300 MW solar PV facility with a tracking mounting system. The project is sited on leased land from the Moapa Band of Paiute Indians and located on the Moapa River Indian Reservation in southern Nevada. 8minutenergy, who is technology agnostic, intends to utilize a combination of solar PV panels, DC to AC inverters, single axis trackers plus associated electrical equipment like transformers and switchgears for the project. The solar energy and battery discharge energy will be routed through the inverters to a step-up transformer, where, as a dispatchable resource, it will be delivered to the Reid Gardner 230 kV substation via a generation intertie shared with 8minutenergy's Eagle Shadow Mountain project.

8minutenergy estimates that SBS will provide 590 jobs during construction. After commercial operation on September 1, 2023, SBS is expected to provide 12 permanent jobs with an average annual salary of $80,000, for an estimated annual payroll of $960,000 and a total payroll of $24.0 million over 25 years. Overall, based on information provided by 8minutenergy, the Companies estimate that the total investment in Nevada's economy directly associated with SBS will be over $396 million. A work site agreement, dated March 8, 2019 was successfully executed between 300MS 8me LLC and IBEW Local Union 357, IBEW Local Union 396 and Laborers Local 872.

The PPA is for a 25-year term at a flat price of $22.32 per MWh during off peak hours and $145.08 per MWh during peak hours. Peak hours are hours ending 1700 through 2100 in June, July and August, the Full Requirements Period. The project has an expected net capacity rating of 300 MW (ac). It is expected to generate 1,014,929 MWh and provide 1,014,929 portfolio credits ("kPCs") in the first year. Annual energy production and credits are projected to degrade at approximately three-tenths percent (0.3 percent) per year. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-6-SBS (a). Figure REN-2 shows a map of the project site.

FIGURE REN-2
SOUTHERN BIGHORN SOLAR – PROJECT SITE



Technical Appendix REN-6-ESM (b) contains detailed information about the Eagle Shadow Mountain Solar project, including the information required by NAC 704.8885 and NAC 704.8887.

c. GEMINI SOLAR 690 MW SOLAR PPA (NEVADA POWER)

The proposed Gemini Solar project is to be developed by Solar Partners XI, LLC ("Arevia") near the Apex Industrial Park in Clark County, Nevada. Arevia and its investor Quinbrook Infrastructure Partners have developed over 2 GW of projects across the world, with a vast majority in the United States.

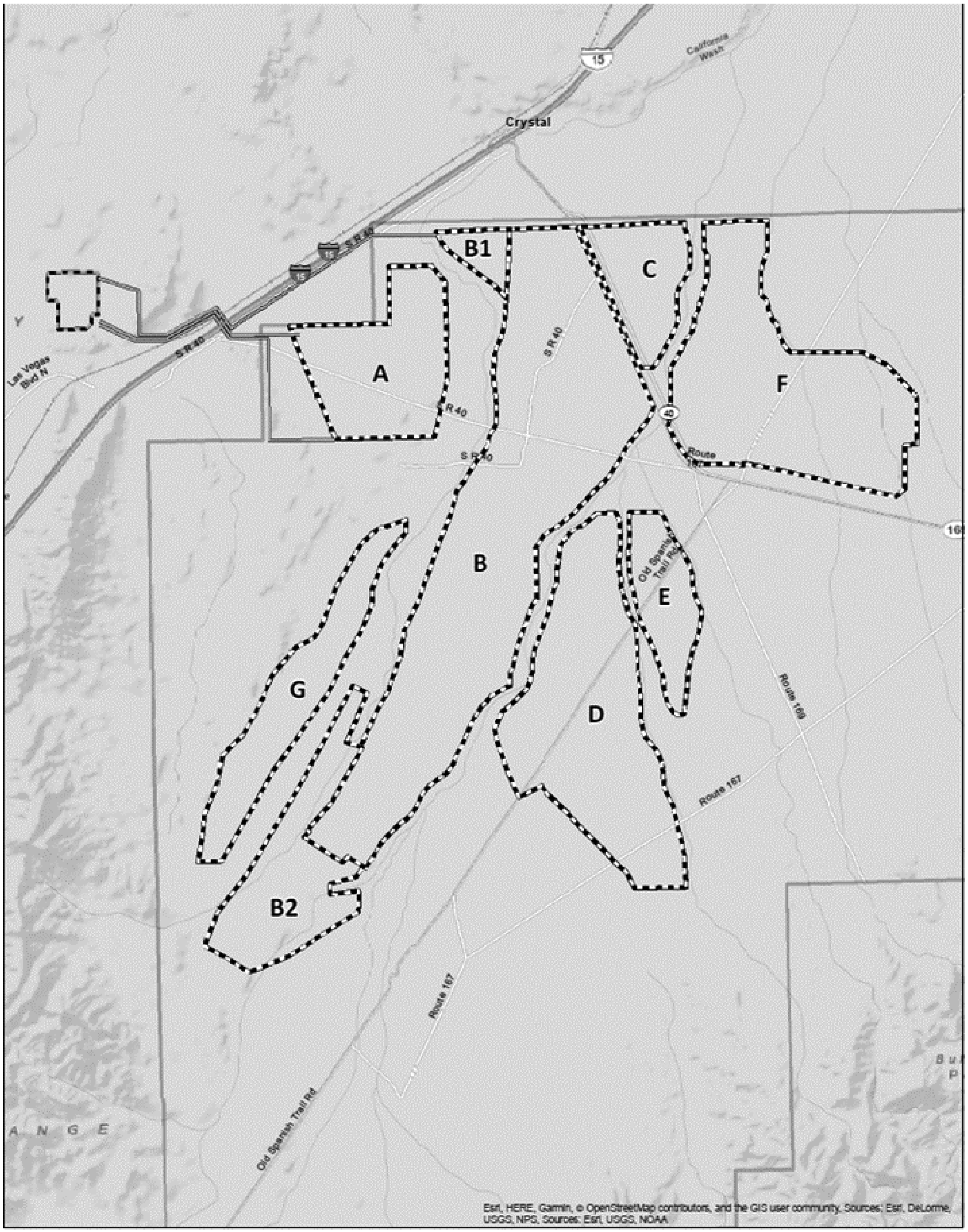
The Gemini project will consist of a 690 MW solar PV facility with a tracking mounting system. The project is sited on Bureau of Land Management land located along the south side of Interstate 15 approximately 25 miles north of Las Vegas, Nevada. Arevia intends to utilize a combination of solar PV panels, DC to AC inverters, single axis trackers plus associated electrical equipment including transformers and switchgear for the project.

Arevia estimates that the Gemini project will provide 2,385 jobs during construction. After commercial operation on December 1, 2023, Gemini is expected to provide 25 permanent jobs with an average annual salary of $79,000, for an estimated annual payroll of $1,975,000 and a total payroll of $63.2 million over 25 years. Overall, based on information provided by Arevia, the

Companies estimate that the total investment in Nevada's economy directly associated with the Gemini project will be nearly $820 million. A work site agreement, dated December 27, 2017 was executed between Arevia and IBEW Local Union 357 and IBEW Local Union 396.

The PPA is for a 25-year term at a flat price of $24.79 per MWh during off peak hours and $161.14 per MWh during peak hours. Peak hours are hours ending 1700 through 2100 in June, July and August, the Full Requirements Period. The project has an expected net capacity rating of 690 MW (ac). It is expected to generate approximately 2,226,581 MWh and 2,226,581 kPCs in the first year. Annual energy production is projected to degrade at approximately (0.5 percent per year. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-6-GS (a). Figure REN-3shows a map of the project site.

FIGURE REN-3
GEMINI SOLAR – PROJECT SITE



5. Network Upgrades Required For The New Agreements

The cost of new network upgrades required to connect the proposed projects was factored into the LCOE. Those network upgrades are described further in the Transmission Plan section of this narrative below.

SECTION 5. AMENDMENTS TO TRANSMISSION PLAN

A. Introduction

This transmission plan is built upon the load forecasts, system characteristics, existing and future transmission facilities and obligations as described in this section. Based in part on these key system characteristics, the transmission plan examines the capabilities of the existing transmission system in order to determine the need for and timing of any additional transmission facilities.

The Companies are requesting Action Plan approval to begin network upgrades associated with four new Generator Interconnection projects. These include network upgrades required to support the development of the following renewable generation projects: Moapa Solar, Southern Bighorn Solar, Apex Solar, and Gemini Solar.

The Companies are also requesting Action Plan approval to begin work on one new transmission growth project, the Apex Industrial 230 kV Switching Station, and one new reliability project, the Machacek 230 kV Breaker Addition.

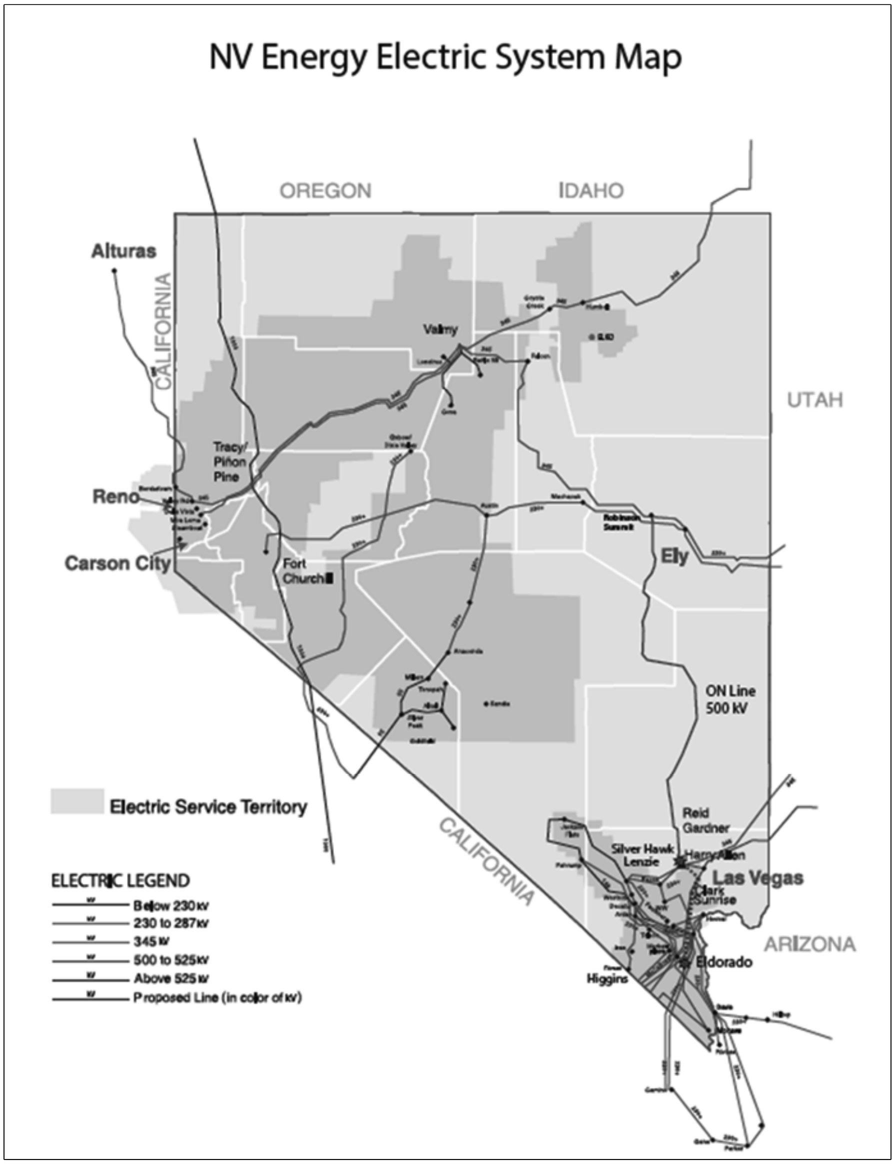
B. Overview of the Companies' Transmission System

The following information has not changed since the Companies filed their 2018 Joint IRP or the Second Amendment to the 2018 Joint IRP. Section 704.9321(3)(e) of the NAC requires the Companies to provide maps depicting facilities required for the transmission of electric energy. This information is set forth in the map marked as Figure TP-1 below. This map shows the transmission system in both the northern and southern parts of Nevada, at each voltage.

The consolidated Nevada Power and Sierra transmission balancing authority area ("BAA") encompasses approximately 50,000 square miles. Nevada Power owns 1,665 miles of FERC-jurisdictional transmission lines with voltages ranging from 69 kV to 500 kV. The Sierra transmission service area encompasses more than 40,000 square miles, with approximately 330,000 electric customers and 2,151 miles of FERC-jurisdictional transmission lines ranging from 55 kV to 345 kV.[19]

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

FIGURE TP-1
NV ENERGY TRANSMISSION SYSTEM DIAGRAM



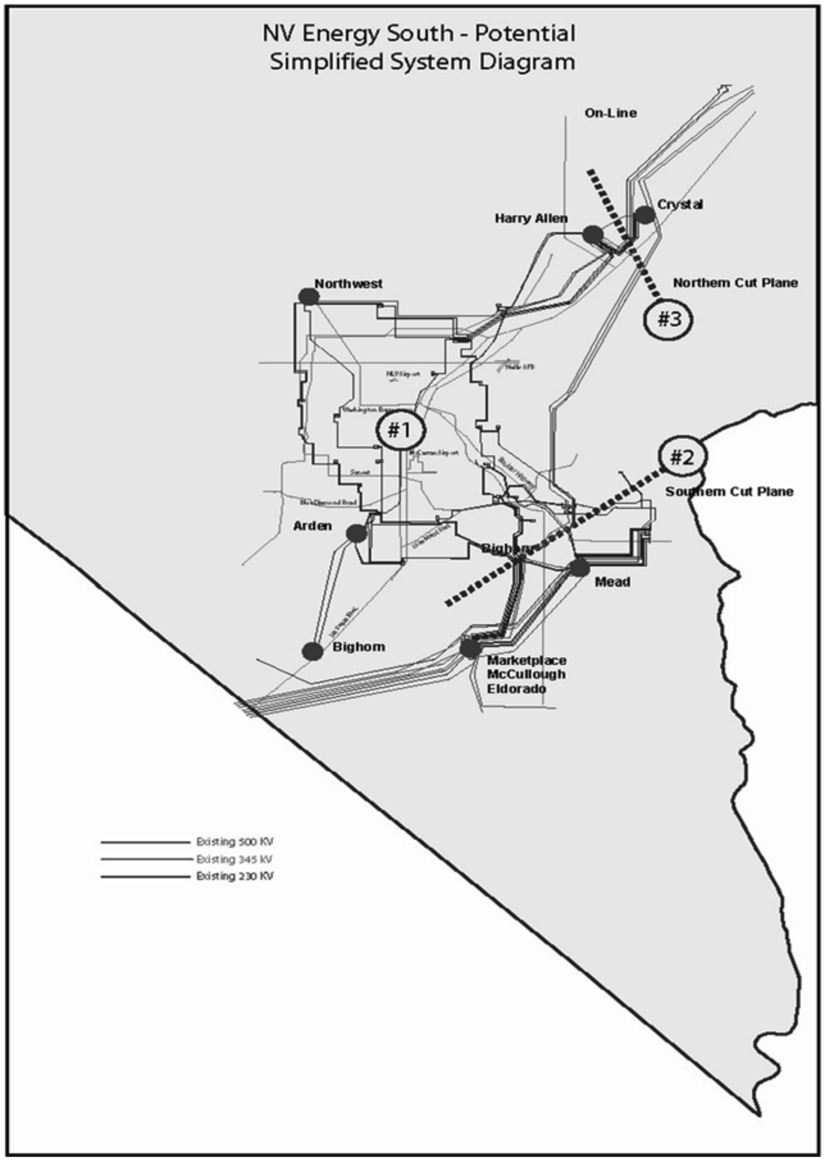
1. NEVADA POWER TRANSMISSION SYSTEM

The existing Nevada Power transmission system can be described in three sections, each of which is depicted in Figure TP-2. The first section, generally referred to as the Nevada Power internal system, is designated by the "#1", and is shown as the area between the cut plane lines (the heavy dashed lines). A cut plane is a reference to a combination of lines, either internal or external to a transmission system, which due to loading capabilities are collectively monitored or examined for limitations. The Nevada Power internal system is located within the Las Vegas Valley where the vast majority of Nevada Power's customers reside.

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

The third section is represented by the dashed line on the top-right of Figure TP-2, designated with a “#3”, is referred to as the Northern Cut Plane (“NCP”), and comprises the Red Butte-Harry Allen 345 kV interconnection with PacifiCorp, and the Crystal interconnection with the Navajo-Crystal-McCullough 500 kV line. Annual studies are conducted in coordination with PacifiCorp to verify the capability of this cut plane.

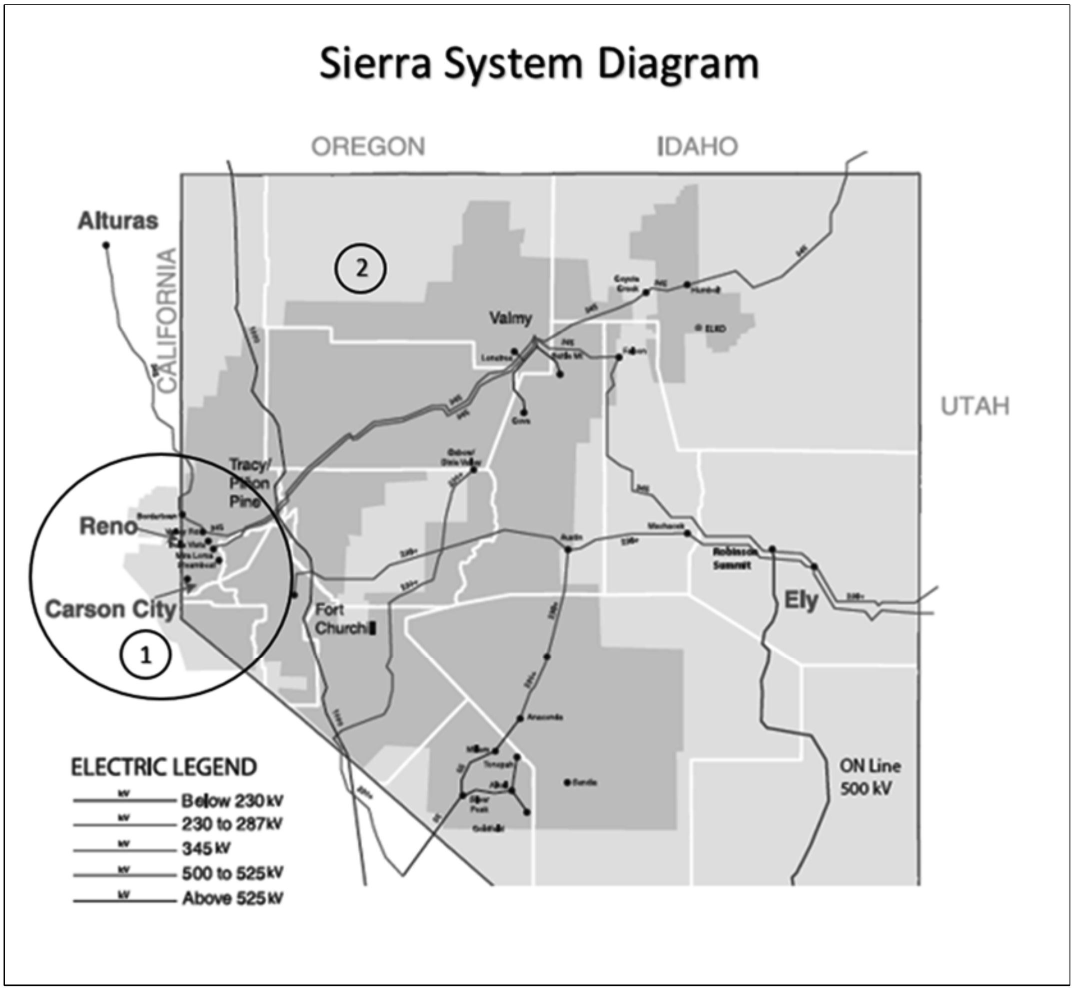
FIGURE TP-2
NEVADA POWER TRANSMISSION SYSTEM DIAGRAM



2. SIERRA TRANSMISSION SYSTEM

The Sierra system is best described as two sections as shown in the map in Figure TP-3 below. The first section, depicted as the area within the circle, encompasses the Reno, Tracy and Carson City areas. Designated with a "1", this section represents the majority of Sierra's system load, and is where the majority of Sierra's customers reside. The second section of the Sierra service area is the area outside the inner circle, designated with the "2", in the northern portion of the state. This section is characterized by long transmission lines serving heavy industrial (i.e., mining) and rural load widely dispersed throughout the northern portion of the state.

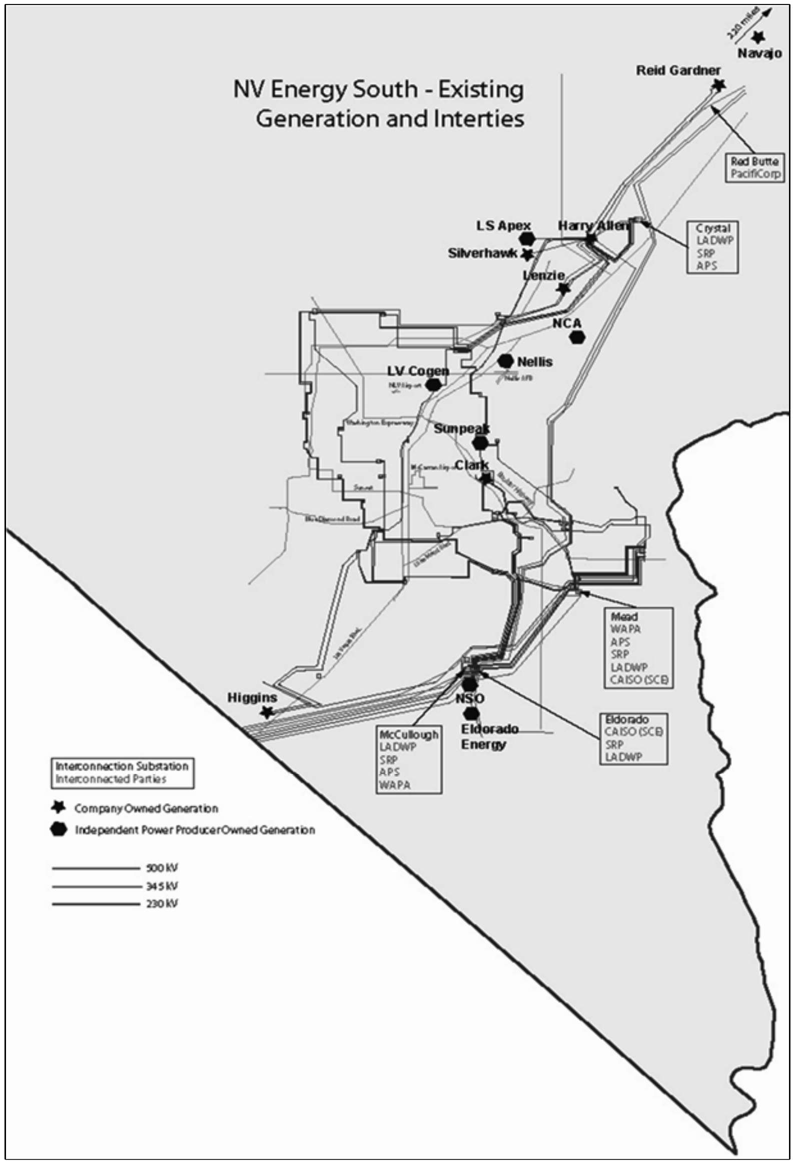
FIGURE TP-3
SIERRA TRANSMISSION SYSTEM DIAGRAM



C. Transmission Path Ratings

The following information has not changed since the Companies filed their 2018 Joint IRP or Second Amendment to the 2018 Joint IRP. Per NAC §704.9385(3)(a), the Transmission Plan must provide a summary of the capabilities of the transmission system, including import and export capabilities and the rating of significant transmission paths. NAC §704.9321(3)(d) requires the Companies to provide information regarding interconnections with other utilities and independent power producers. Nevada Power owns three significant rated transmission paths, as shown below in Figure TP-4, each consisting of one or more transmission lines that are granted a rating by the WECC. Nevada Power is a partial owner of one additional WECC-rated transmission path, that being the WECC East of River ("EOR") Path 49.

FIGURE TP-4
DIAGRAM OF NEVADA POWER TIE LINES, EXISTING COMPANY-OWNED GENERATION, AND EXISTING INDEPENDENT GENERATION



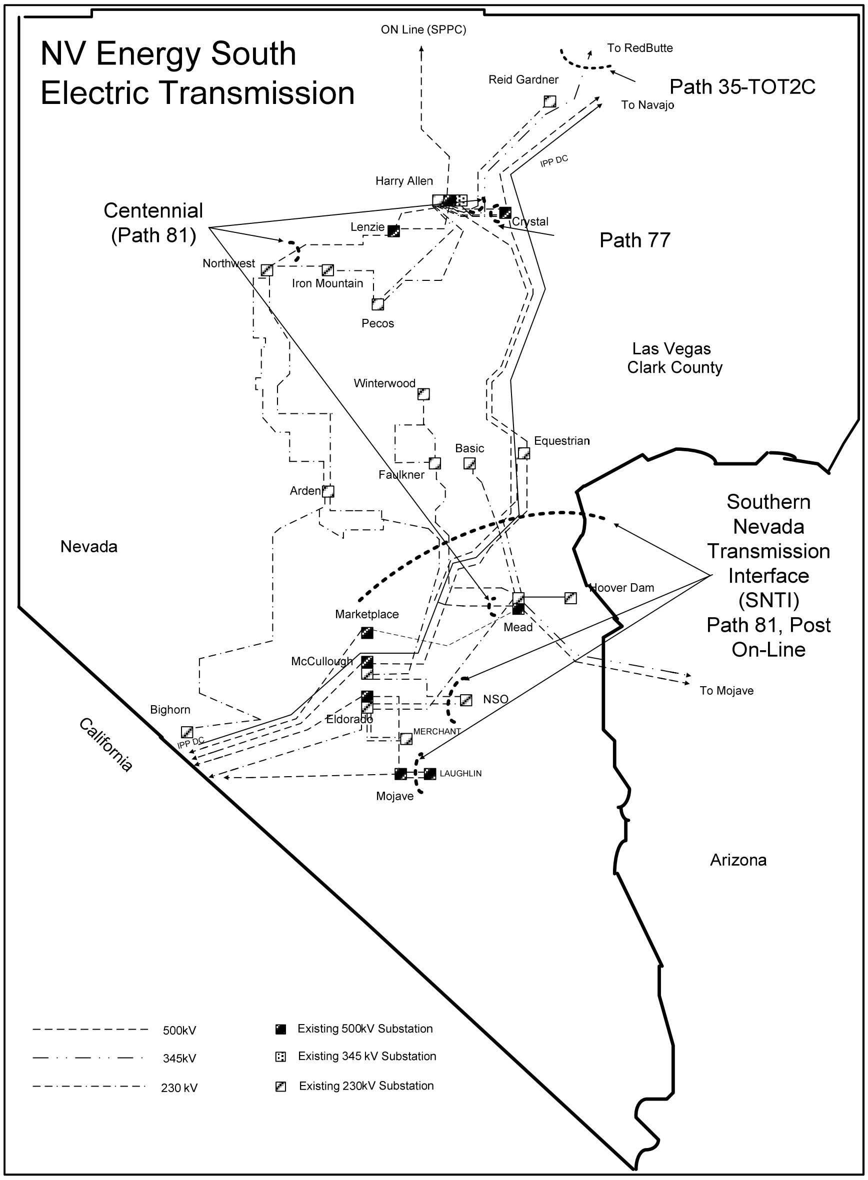
Crystal 500 / 230 kV Path (WECC Path # 77). The Crystal 500/230 kV path allows energy to be moved from the Navajo-Crystal-McCullough 500 kV transmission line into the northeast boundary of the Nevada Power system via its Crystal Substation. This path is rated for 950 MW of inbound flow measured at the Crystal Substation. This is a 230 kV phase shifter-controlled path.

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

<u>Southern Nevada Transmission Interface (WECC Path #81)</u>. Nevada Power owns and operates the Southern Nevada Transmission Interface, or SNTI, shown below in Figure TP-5. SNTI is comprised of 21 transmission tie-lines between the Nevada Power/Sierra combined BAA and the neighboring BAAs in southern Nevada (Western Area Power Administration, Lower Colorado, Los Angeles Department of Water and Power, and the California Independent System Operator ("CAISO"). This can be seen in Figure TP-4. The SNTI represents existing lines, and the path is routinely evaluated and annually updated as a part of the NV Energy seasonal operating studies. The accepted SNTI rating as approved by WECC is 4,533 MW North-to-South and 3,970 MW South-to-North.

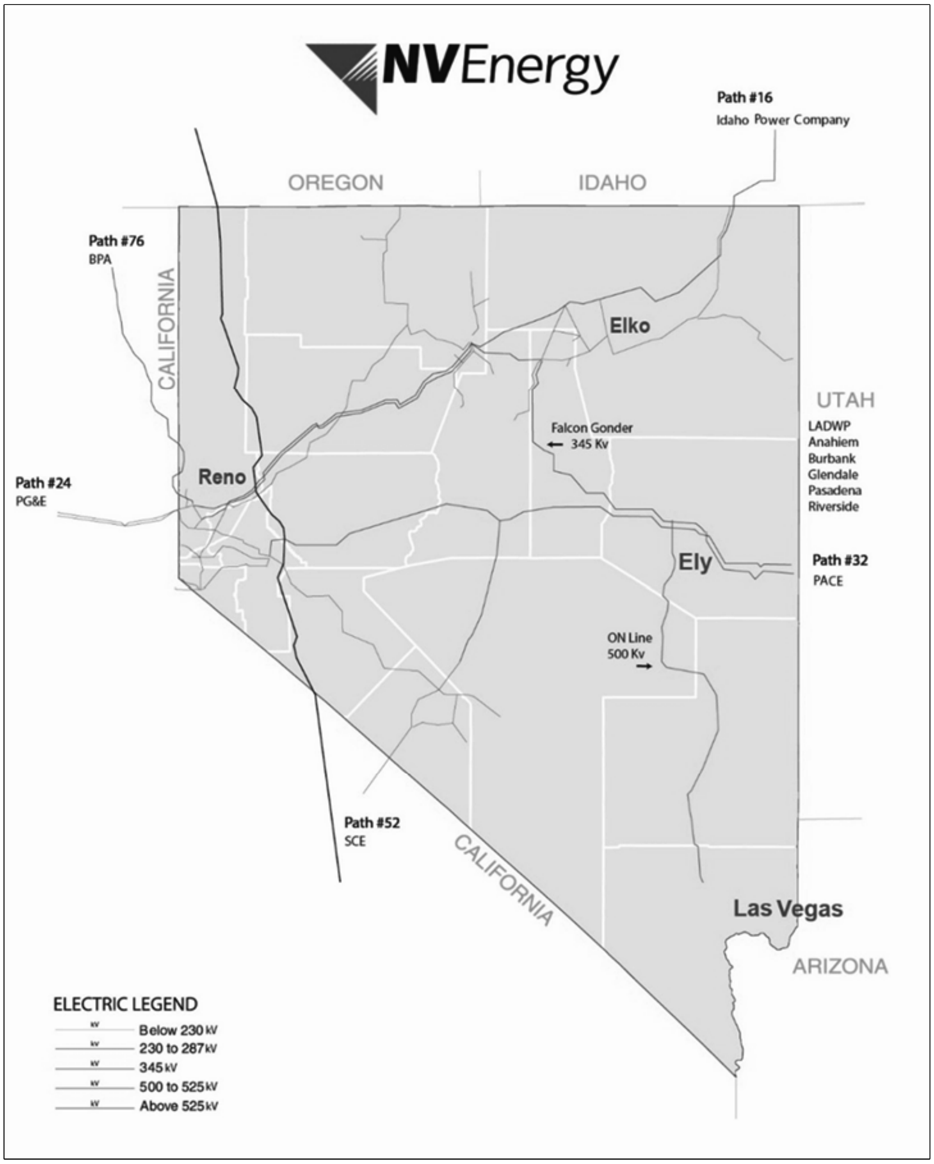
<u>Regional Projects Affecting Nevada Power Capacity Rights.</u> In 2014, the CAISO announced its intent to seek bids for the construction a new 500 kV transmission line between Nevada Power's Harry Allen substation and Southern California Edison's ("SCE") Eldorado substation ("HAE Project"). CAISO is sponsoring the line for the benefit of CAISO and its customers. The expected in service date of the HAE Project is May 2020. LS Power Associates, L.P. ("LS Power") has been awarded the bid. Nevada Power and Sierra have executed certain agreements with LS Power to support LS Power's bid and continue to work with LS Power, CAISO and SCE on the project. The line will improve reliability of Nevada and California systems, enhance import capabilities by approximately 100 MW and increase total Nevada Power's export capability through the SCP by approximately 1,000 MW.

FIGURE TP-5
SOUTHERN NEVADA TRANSMISSION INTERFACES



Sierra owns five WECC rated transmission paths, each consisting of one or more transmission lines. Rated transmission paths are identified in Figure TP-6 below. Ratings are established through the WECC process on a non-simultaneous basis. These transmission path ratings may be subject to change over the 20-year planning period, depending on changes to the system configuration. Operation of the paths are based on simultaneous limits described as Operational Transfer Capabilities and are posted on Sierra’s Open Access Same-time Information System (“OASIS”).

FIGURE TP-6
SIERRA RATED TRANSMISSION PATHS



<u>Idaho – Sierra (WECC Path # 16)</u>. This path is rated for 500 MW of inbound flow and 360 MW of outbound flow. The path is a 345 kV line from Idaho Power's Midpoint Substation, near Twin Falls, Idaho that connects to Sierra's Humboldt Substation in the northeast corner of the Sierra's transmission system.

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

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

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

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

1. Import Capability

The following information has not changed since the Companies filed the Second Amendment to the 2018 Joint IRP, Docket No. 19-05003. Section §704.9385(3)(a) of the NAC requires that the Transmission Plan describe the import capability of the transmission system. The term "import capability" is defined as the energy that can be transferred into a BAA and should not be confused with long-term firm transmission capability under the OATT. Import capability is determined in accordance with WECC and North American Electric Reliability Corporation ("NERC") reliability criteria. Under WECC and NERC criteria, a system must be capable of meeting all performance criteria for steady state and single contingency outage conditions at the stated import level. Thus the Companies' system import capabilities are dependent on transmission line flows, generation dispatch patterns, and system loads. "Imports" equal load plus losses minus internal generation, or:

Imports = load + losses – internal generation

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

Figure TP-7 below shows the individual Sierra and Nevada Power system import capabilities through 2023 using the FERC's prescribed methods. These values reflect the system import limit using balanced line flows. Internal generation is adjusted in the study to allow maximum system import capability. This figure does not provide a complete representation of each system's real-time import capabilities, as imports are dependent on load and the generation used to meet such load.

FIGURE TP-7
SUMMARY OF SYSTEM IMPORT CAPABILITY

Summary of Import Capability (MW)					
	2019	**2020**	**2021**	**2022**	**2023+**
Nevada Power	5100	5200	5200	5200	5200
Sierra	1275	1275	1275	1275	1275

Maximum import capability (distinct from long-term, firm transmission capability under the OATT) is measured using maximum load and minimum generation, where actual imports are highly dependent on load, generation and available voltage support. Long-term, firm transmission service under the OATT, on the other hand, must be available without limits imposed by load variations or other transmission customers' actions.

The Nevada Power import limit increases from 5100 MW to 5200 MW in 2020. This increase is attributed to the results of an initial analysis performed to address the addition of the Harry Allen to Eldorado 500 kV line. The natural flow of the system is from Harry Allen substation into Eldorado and Mead. The moderate 100 MW increase of import is not unexpected for this connection. The company will re-evaluate the impact on import capability before the project goes into service in May 2020.

In November 2018, a restudy of the northern Nevada system identified discrepancies that impacted the calculation of the import capability of the northern Nevada system. The study was triggered by substantial changes in transmission planning reliability criteria since ON Line went into service, as well as decreases in facility ratings resulting from a 2017 review and overhaul of facility ratings throughout the system. As a result of this work, ratings on some 345/120 kV transformers were decreased. These transformers are key to the import capability of the system because they deliver energy from the overarching 345 kV system to the load on the 120 kV system.

It should be noted that the system import limit is not a theoretical maximum, but rather an operational limit that can be managed every day of every year. The reassessment of the import limit affirmed the 1275 MW limit that currently exists and does not propose any changes to it.

2. Export Capability

The following information has changed since the Companies filed their 2018 Joint IRP, but has not changed since the Companies filed the Second Amendment to the 2018 Joint IRP. Section 704.9385(3)(a) of the NAC requires that the Transmission Plan describe the export capability of the transmission system. Nevada Power's and Sierra's system export capability are set forth in Figure TP-8 below. Export capability is limited by the capability of the transmission system, including load and generation. Export capability of the system is generally limited by the loss of the highest rated intertie.

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

FIGURE TP-8
SUMMARY OF EXPORT CAPABILITY

Summary of Export Capability (MW)					
	2019	**2020**	**2021**	**2022**	**2023+**
Nevada Power	4533	6090	6090	6090	6090
Sierra	1125	1125	1330	1330	1330

The Nevada Power export limit increases from 4533 MW to 6090 MW in 2020. This increase is attributed to the results of an initial analysis performed to address the addition of the Harry Allen to Eldorado 500 kV line. The natural flow of the system is from Harry Allen substation into Eldorado and Mead. The high capacity 500 kV line provides significant additional export capability. At this time, this limit is subject to change based on discussion and additional analysis being conducted with the developer of the Harry Allen to Eldorado line. The company will re-evaluate the impact on export capability before the project goes into service in May 2020.

In parallel with the Sierra import limit analysis, the Sierra export limit was also reassessed in 2019. Established in 2011, the published export limit of 750 MW was a resource rather than reliability limited capacity. Since the 750 MW export level was last established, several new resources have been added to the Sierra system. The updated export capacity for the Sierra system is 1125 MW and this limit will be increased to 1330 MW when the Bordertown to California project is constructed along with associated facility rating updates at California Substation.

D. Transmission Service Obligations

The following information has not changed since the Companies filed their Second Amendment to the 2018 Joint IRP. Per NAC §704.9385(3)(c) and NAC §704.9385(3)(d), the transmission plan must identify the transmission capacity required to serve bundled and unbundled retail transmission customers, and wholesale transmission customers the Companies are obligated to serve, as well as all existing and proposed transmission service agreements ("TSAs") with transmission customers. The regulations require that the transmission plan identify the expiration dates of all such obligations and their impacts on the transmission capacity available for use by bundled retail customers.

Nevada Power and Sierra provide transmission-only service to several transmission-only customers under TSAs. Existing Nevada Power TSAs are listed in Figures TP-9 and TP-10. Figure TP-9 lists Nevada Power's long-term transmission obligations for import into the BAA. Figure

TP-10 lists Nevada Power's long-term transmission obligations for exports out of the BAA. Existing Sierra TSAs are listed in Figures TP-11 and TP-12. Figure TP-11 shows Sierra's long term transmission obligations for import into the BAA, and Figure TP-12 shows Sierra's long term transmission obligations for exports out of the BAA. Figure TP-13 shows a summary of the Northern and Southern import and export obligations by point of delivery.

FIGURE TP-9
NEVADA POWER'S LONG-TERM BAA TRANSMISSION IMPORT OBLIGATIONS (NETWORK CUSTOMERS)

Agreement	Delivery Interface	MW	Term
SNWA	Mead 230 kV	30	6/1/2013 - 5/31/2023
LVVWD	Mead 230 kV	60	6/1/2013 - 5/31/2023
City of Las Vegas	Mead 230 kV	8	6/1/2013 - 5/31/2023
City of Henderson	Mead 230 kV	10	6/1/2013 - 5/31/2023
City of North Las Vegas	Mead 230 kV	4	6/1/2013 - 5/31/2023
Clark County Water Reclamation District	Mead 230 kV	13	6/1/2013 - 5/31/2023
Wynn Las Vegas	Mead 230 kV	31	10/1/2016 - 10/1/2036
MGM Resorts Inc.	Mead 230 kV	174	10/1/2016 - 10/1/2021
Switch Ltd.	Mead 230 kV	87	6/1/2017 - 6/1/2047
Caesar's Enterprises	Mead 230 kV	87	2/1/2018-2/1/2023

FIGURE TP-10
NEVADA POWER POINT OF DELIVERY LONG-TERM BAA TRANSMISSION EXPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Term
ONGP – ORNI 43	Crystal 500 kV	24	02/01/2019 - 10/1/2022
ONGP - Steamboat	Crystal 500 kV	14	2/1/2019-2/1/2023
ONGP – ORNI 39	Crystal 500 kV	30	2/01/2019 - 12/1/2023
ONGP – ORNI 39	Crystal 500 kV	24	1/1/2019 - 1/1/2024
ORNI 43	Crystal 500 kV	8	1/1/2019 - 1/1/2020
ONGP – ORNI 39	Crystal 500 kV	6	1/1/2019 - 1/1/2020
ORNI 32	Crystal 500 kV	24	1/1/2020-1/1/2025
ORNI 52	Crystal 500 kV	24	1/1/2020-1/1/2025
Ormat - Dixie Comstock	Crystal 500 kV	25	01/01/2022-01/01/2027
Ormat - Brady	Crystal 500 kV	16	8/1/2022-8/1/2027
Ormat - Steamboat	Crystal 500 kV	24	12/1/2022-12/1/2027
ORNI 43	Crystal 500 kV	8	1/1/2018 - 1/1/2019
Ormat - Alum	Crystal 500 kV	25	1/1/2025-1/1/2030
ORNI 32	Crystal 500 kV	6	1/1/2020-1/1/2025
Ormat - Steamboat	Crystal 500 kV	24	1/1/2020-1/1/2025
MSCG – Midpoint 345 kV	Eldorado 230 kV	50	3/1/2016 - 3/1/2021
SCPPA - Harry Allen 500 kV	McCullough 500 kV	500	12/1/2015 -7/30/2023
ORNI 47	Mead 230 kV	24	1/1/2014 - 12/31/2033
ORNI 37	Mead 230 kV	21	10/1/2016 - 1/1/2021
ORNI 37	Mead 230 kV	3	10/1/2016 - 12/31/2033
Patua - Ragtown 63 kV	Mead 230 kV	6	4/1/2018-10/1/2021
Salt River Project	Navajo 500 kV	25	12/1/2018 -12/01/2023

FIGURE TP-11
SIERRA LONG TERM BAA TRANSMISSION IMPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Term
Truckee Donner PUD	Gonder Pavant	41	11/1/2016 - 1/1/2025
Barrick	Gonder Pavant	75	1/1/2014 - 1/1/2024
Mt Wheeler	Gonder Pavant	80	6/1/2016 - 6/1/2021
City of Fallon	Gonder IPP	15	4/1/2017 - 4/1/2022
Mt Wheeler	Gonder IPP	25	1/26/2017 - 6/1/2021
BPA – Wells	Hilltop 345 kV	85	10/1/2016 - 10/1/2028
BPA – Harney	Hilltop 345 kV	35	10/1/2016 - 10/1/2028
City of Fallon	Midpoint 345 kV	10	4/1/2017 – 4/1/2022
Barrick	Midpoint 345 kV	18	1/1/2016 - 1/1/2020
Barrick	Midpoint 345 kV	82	1/1/2016 - 1/1/2029
Barrick	Midpoint 345 kV	6	1/1/2016 - 1/1/2028
Switch Ltd.	Midpoint 345 kV	23	6/1/2017 - 6/1/2047
Caesar’s Enterprises	Midpoint 345 kV	10	9/1/2017 - 9/1/2022
Peppermill Resorts	Midpoint 345 kV	9	1/1/2018 - 1/1/2048
Liberty Utilities	Midpoint 345 kV	11	5/1/2019 - 5/1/2049

[1] Network Customers’ import rights are equal to Designated Network Resources (“DNRs”) and may not have a termination date based on contract and roll-over rights.

[2] DNRs that impact transmission capacity on Path 32.

FIGURE TP-12
NORTHERN POINT OF DELIVERY LONG TERM BAA TRANSMISSION EXPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Term
Patua Project LLC - Eagle 120 kV	Hilltop 345 kV	18	10/1/2018 - 10/1/2023[1]
Patua Project LLC - Eagle 120 kV	Hilltop 345 kV	4	1/1/2019 - 10/01/2021[1]
Patua Project LLC - Ragtown 63 kV	Gonder Pavant	7	1/1/2019 - 10/1/2021[1]
Patua Project LLC - Ragtown 63 kV	Gonder Pavant	13	1/1/2019 - 10/1/2021[1]
ARP - Loyalton 63 kV	Summit 120 kV	18	4/1/2018 - 4/1/2023[1]
Idaho Valmy	Midpoint 345 kV	262	N/A

1. Subject to roll over rights.

Figure TP-13 below is a summary of the long term transmission import and export obligations at each point of delivery in Figures TP-9 through TP-12.

FIGURE TP-13
NV ENERGY LONG TERM BAA TRANSMISSION OBLIGATIONS SUMMARY

		Point of Delivery	MW Total
Nevada Power	**Import Obligations**	Mead 230 kV	**504**
	Export Obligations	Crystal 500 kV	**282**
		Eldorado 230 kV	**50**
		McCullough 500 kV	**500**
		Mead 230 kV	**54**
		Navajo 500 kV	**25**
Sierra	**Import Obligations**	Gonder/ Pavant 230 kV	**196**
		Gonder IPP	**40**
		Hilltop 345 kV	**120**
		Midpoint 345 kV	**169**
	Export Obligations	Hilltop 345 kV	**22**
		Gonder/ Pavant 230 kV	**20**
		Summit 120 kV	**18**
		Midpoint 345 kV	**262**

NAC 704.9385(3)(e) requires the Companies provide "a table identifying all the transmission capacity that the utility has secured for its bundled retail transmission customers on both its transmission system and the transmission systems of other utilities." Figure TP-14 and TP-15 below show the Companies' long-term secured transmission capacity for bundled retail customers.

FIGURE TP-14
NEVADA POWER TRANSMISSION CAPACITY SECURED FOR BUNDLED RETAIL TRANSMISSION CUSTOMERS

	Firm Capacity Reserved by Nevada Power for Native Load									
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Mead (Hoover)	355	355	355	355	355	355	355	355	355	355
Red Butte	0	0	0	0	0	0	0	0	0	0
McCullough	0	0	0	0	0	0	0	0	0	0
Crystal (Navajo)	260	260	260	260	260	260	260	260	260	260
Eldorado	0	0	0	0	0	0	0	0	0	0
Mohave (Laughlin)	50	50	50	50	50	50	50	50	50	50
ON Line (Sierra)	526	526	526	526	526	526	526	526	526	526
Total	1191	1191	1191	1191	1191	1191	1191	1191	1191	1191
	Firm Capacity Reserved by Nevada Power on Other Systems									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	0	0	0	0	0	0	0	0	0	0

FIGURE TP-15
SIERRA TRANSMISSION CAPACITY SECURED FOR BUNDLED RETAIL TRANSMISSION CUSTOMERS

	Firm Capacity Reserved by Sierra for Native Load									
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Nevada Power (ON Line)	600	600	600	600	600	600	600	600	600	600
Total	600	600	600	600	600	600	600	600	600	600
	Firm Capacity Reserved by Sierra on Other Systems									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	0	0	0	0	0	0	0	0	0	0

NAC § 704.945(4) requires "a graph or table" that depicts "the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers." This information is provided for the Companies in TP-16, below.

FIGURE TP-16
NV ENERGY TRANSMISSION SYSTEM CAPACITY ALLOCATION

	Nevada Power		**Sierra**	
Transmission Allocation	**MW**	**Percentage**	**MW**	**Percentage**
Unbundled/ Wholesale Transmission	504	9.9%	525	41.2%
Bundled Transmission	1191	23.4%	600	47.1%
Transmission Reliability Margin	175	3.4%	150	11.8%
Unallocated Transmission	3230	63.3%	0	0.0%
Total Import Capacity	**5100**		**1275**	

E. Specific Requests for Commission Approval for New Transmission Projects

NAC § 704.9385(3)(b) requires that the Transmission Plan include a description of transmission projects that the Companies are considering to expand or upgrade. NAC § 704.9355(1)(b) and (1)(c) require that the utilities develop a set of analyses of its options for supply to be considered for meeting the expected future demand on its system. These analyses must include an examination of the environmental impact of each option, taking into account the best available technologies and the environmental benefit of renewable resources, including construction of new transmission facilities or upgrades to existing transmission facilities and purchase of long-term transmission rights on third party transmission facilities. The Companies are requesting Commission approval of four new Generator Interconnection projects. These include network upgrades required to support the development of the following renewable generation projects totaling 1190 MW: Moapa Solar (200 MW at Harry Allen 230 kV), Southern Bighorn Solar (300 MW at Reid Gardener 230 kV), Apex Solar (440 MW at Crystal 230 kV) and Gemini Solar (250 MW at 500 kV).

The Companies are also requesting Action Plan approval to begin work on one new transmission growth project, the Apex Industrial 230 kV Switching Station, and one new reliability project, the Machacek 230 kV Breaker Addition.

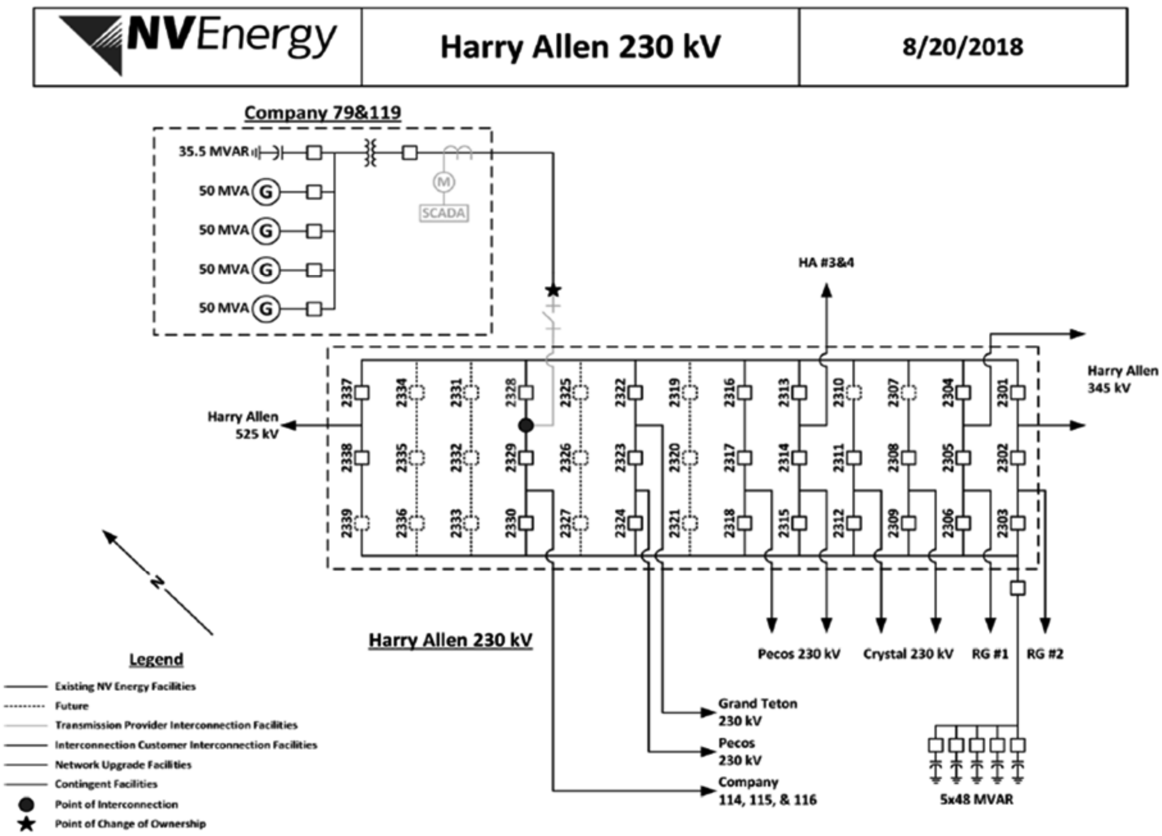
1. Moapa Solar (Company 79/119) Generator Interconnection

EDF Renewables has requested Nevada Power provide interconnection and necessary network upgrades at the Harry Allen 230 kV Substation to support the addition of its Moapa Solar project, a 200 MW solar PV generating facility with up to 75 MW of battery storage, not to exceed 200

MW delivered at Harry Allen 230 kV Substation. EDF Renewables submitted its project as part of the Companies' 2018 renewable request for proposals. The proposed in service date for this project is December 1, 2022. The Large Generator Interconnection Agreement ("LGIA") for this project is included in the Technical Appendix Item TRAN-1.

Construction Scope: Nevada Power will construct the new Harry Allen 230 kV terminal position at the existing Harry Allen 230 kV substation, including installation of one new 230 kV breaker. Figure TP-17 below depicts a single line diagram of the proposed project.

FIGURE TP-17
ONE LINE DIAGRAM OF MOAPA SOLAR (COMPANY 79/119) GENERATION INTERCONNECTION



Budget and Cost Responsibility: EDF Renewables is responsible for the cost of building its generator, lead line, and associated interconnection facilities, including required communications, protections and metering facilities. Nevada Power is responsible for the cost associated with Network Upgrades, per the OATT, which include the new terminal position at the existing Harry Allen 230 kV substation with an estimated cost of approximately $1.3 million. Projected cash flows for the project are shown in Figure TP-18 below:

FIGURE TP-18
PROJECTED CASH FLOWS FOR MOAPA SOLAR GENERATION INTERCONNECTION

Moapa Solar (Company 79/119) Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$1,300,000	$0	$0	$0	$130,000	$130,000	$1,170,000

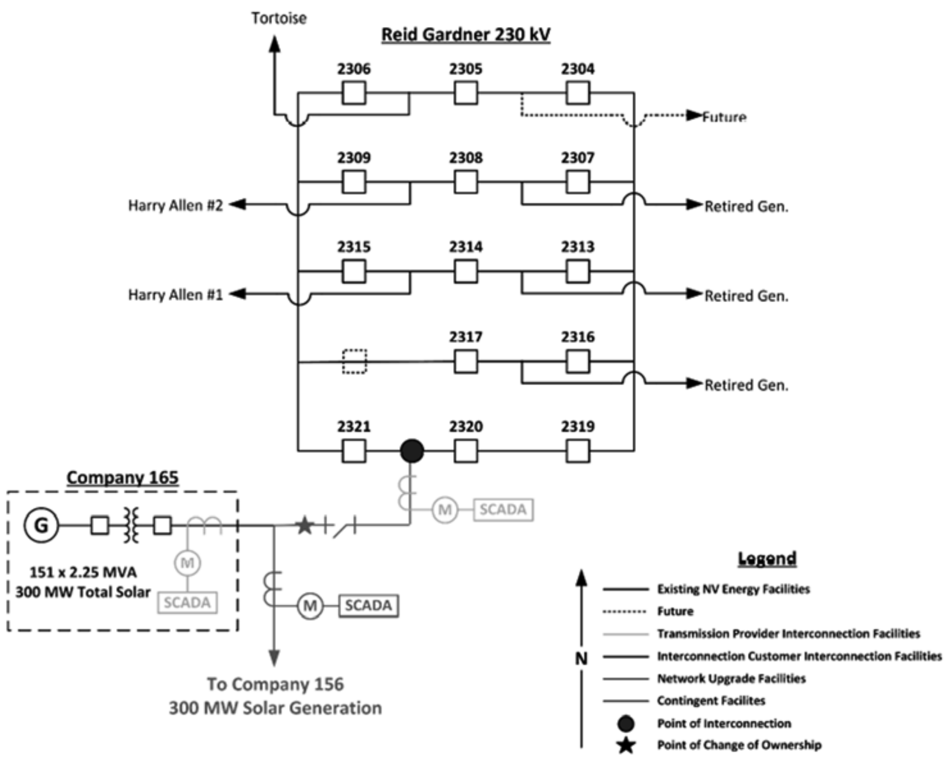
2. Southern Bighorn Solar (Company 165) Generator Interconnection

8 Minute Energy has requested Nevada Power provide interconnection and necessary network upgrades at the Reid Gardner 230 kV Substation to support the addition of its Southern Bighorn Solar (formerly Eagle Shadow Mountain 2) project, a 300 MW solar PV generating facility with up to 135 MW of battery storage, not to exceed 300 MW delivered at Reid Gardner 230 kV Substation. 8 Minute Energy submitted its project as part of the Companies' 2018 renewable request for proposals. The proposed in service date for this project is September 1, 2023. The Re-System Impact Study for this project is included in the Technical Appendix Item TRAN-2.

<u>Construction Scope</u>: Nevada Power is responsible for constructing the Network Upgrades associated with the requested generation addition at Reid Gardner 230 kV substation, including the necessary Network Upgrades to support the generation cluster in the System Impact Study. The scope of these upgrades as they are defined in the most recently updated System Impact Study include 8 Minute Energy's pro rata share of the addition of a new Pecos 230/138 kV transformer. These Network Upgrades are subject to change, as the System Impact Study phase of the Interconnection process can be dynamic, and is entirely dependent on the amount of generation proposed in the Interconnection cluster. Figure TP-19 below depicts a single line diagram of the proposed project.

FIGURE TP-19
ONE LINE DIAGRAM OF SOUTHERN BIGHORN SOLAR 2 (COMPANY 165) GENERATION INTERCONNECTION

NVEnergy	Reid Gardner 230 kV Substation	1/28/2019



<u>Budget and Cost Responsibility</u>: 8 Minute Energy is responsible for the cost of building its generator, shared lead line, and associated interconnection facilities, including required communications, protections and metering facilities. Nevada Power is responsible for the cost associated with Network Upgrades, per the OATT, which currently include 8 Minute Energy's pro rata share of the addition of a Pecos 230/138 kV transformer, with an estimated cost allocation of approximately $3.670 million. This cost, however, is expected to change as the System Impact Study phase of the Interconnection Cluster moves forward. Projected cash flows for the project are shown in Figure TP-20 below:

FIGURE TP-20
PROJECTED CASH FLOWS FOR SOUTHERN BIGHORN SOLAR 2 GENERATION INTERCONNECTION

Southern Bighorn Solar 2 (Company 165) Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$3,670,000	$0	$0	$0	$367,000	$367,000	$3,303,000

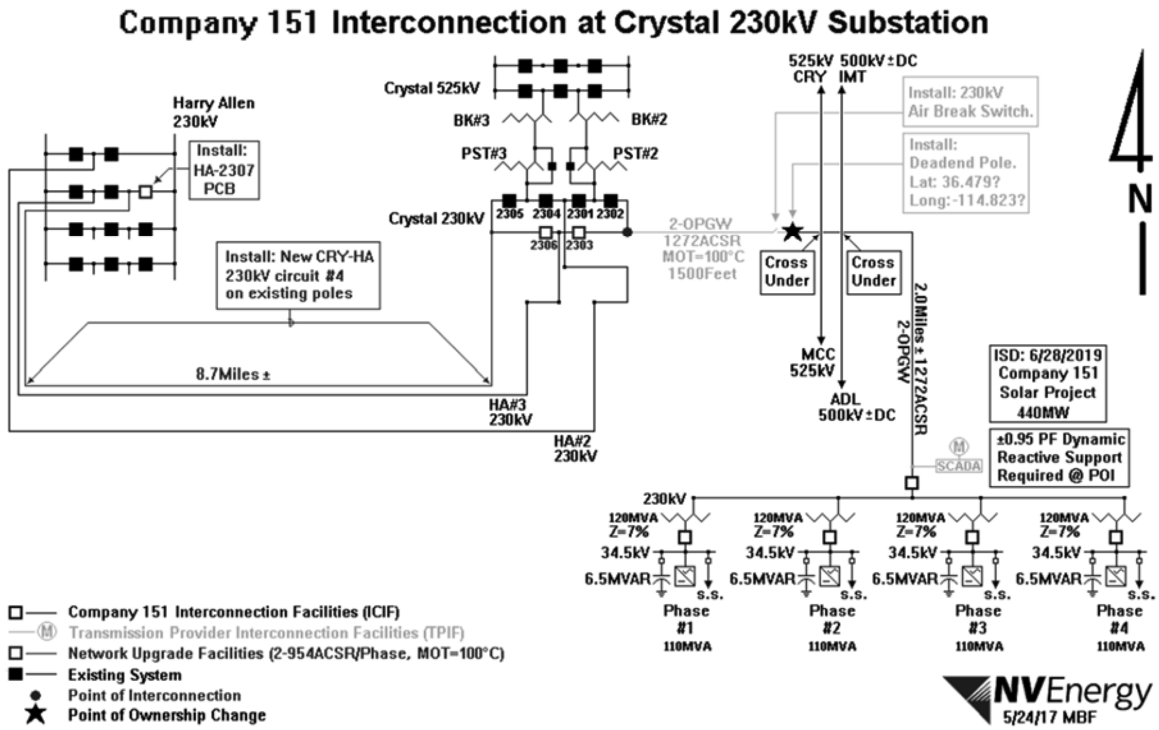
3. Apex Solar (Company 151) Generator Interconnection

Arevia Power has requested Nevada Power provide interconnection and necessary network upgrades at the Crystal 230 kV Substation to support the addition of its Apex Solar project, a 440 MW solar PV generating facility with up to 242 MW of battery storage, not to exceed 440 MW delivered at Crystal 230 kV Substation.[20] Arevia Power submitted its project as part of the Companies' 2018 renewable request for proposals. The proposed in service date for this project is December 1, 2023. The Interconnection Agreement for this request is included in the Technical Appendix Item TRAN-3.

Construction Scope: Nevada Power is responsible for constructing the Network Upgrades associated with the generation addition at Crystal 230 kV substation. The scope of these upgrades include a new 230 kV line, from Harry Allen to Crystal 230 kV, required associated communications, and permitting for environmental and lands. Figure TP-21 below depicts a single line diagram of the proposed Apex Solar project.

[20] Arevia Power has two separate interconnection requests (one for Apex Solar and the other for Gemini Solar, discussed below). However, Arevia Power executed a single PPA for the combined output of both projects and capacity from the battery storage.

FIGURE TP-21
ONE LINE DIAGRAM OF APEX SOLAR (COMPANY 151) GENERATION INTERCONNECTION



Budget and Cost Responsibility: Arevia Power is responsible for the cost of building its generator, shared lead line, and associated interconnection facilities, including required communications, protections and metering facilities. Nevada Power is responsible for the cost associated with Network Upgrades, per the OATT, which include a new the Harry Allen to Crystal 230 kV line and associated terminal positions, protection equipment, lands and permitting for the project with an estimated cost of approximately $9.930 million. Projected cash flows for the Apex Solar project are shown in Figure TP-22 below:

FIGURE TP-22
PROJECTED CASH FLOWS FOR APEX SOLAR GENERATION INTERCONNECTION

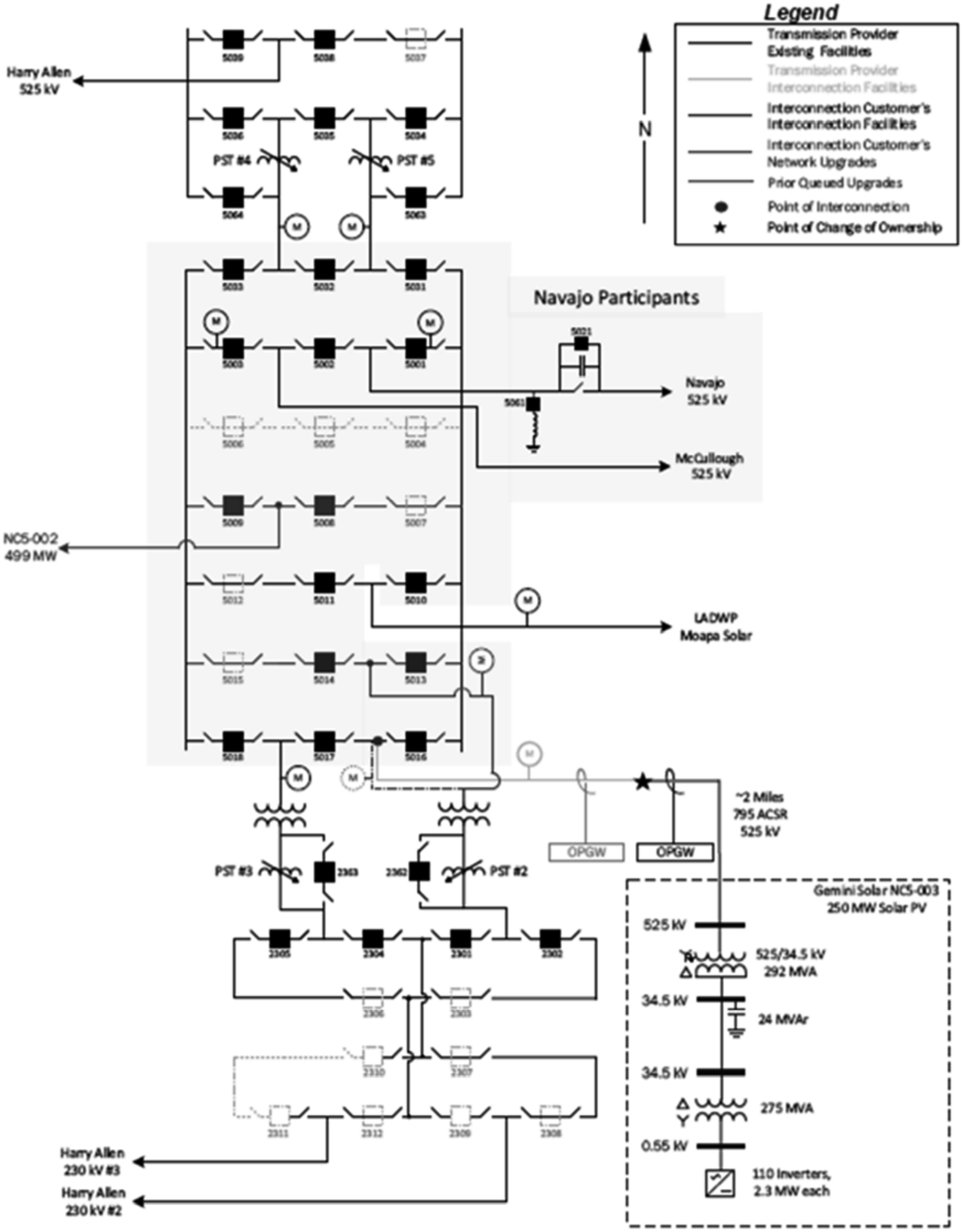
Apex Solar (Company 151) Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$9,930,000	$0	$0	$0	$993,000	$993,000	$8,937,000

4. Gemini Solar (Company Nc5-002) Generator Interconnection

Arevia Power has requested Nevada Power provide interconnection and necessary network upgrades at the Crystal 500 kV Substation to support the addition of its Gemini Solar project, a total of 250 MW solar PV generating facility with up to 138 MW of battery storage, not to exceed 250 MW delivered at Crystal 500 kV Substation. Invenergy submitted its project as part of the Companies' 2018 renewable request for proposals. The proposed in service date for Gemini Solar is December 1, 2023. The System Impact Study for this Interconnection request, as part of the Navajo Transmission Project, is included in the Technical Appendix Item TRAN-4.

Construction Scope: Nevada Power is responsible for constructing the Network Upgrades associated with the generation addition at Crystal 500 kV substation. The construction scope includes a new 500 kV terminal position at South Crystal substation, two associated 500 kV breakers, the re-termination of the existing 500/230 kV transformer #2, and required metering and protections equipment. Figure TP-23 below depicts a single line diagram of the proposed Gemini Solar project.

FIGURE TP-23
ONE LINE DIAGRAM OF GEMINI SOLAR GENERATION INTERCONNECTION



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Budget and Cost Responsibility: Arevia Power is responsible for the cost of building its generator, shared lead line, and associated interconnection facilities, including required communications, protections and metering facilities. Nevada Power is responsible for the cost associated with Network Upgrades, per the OATT, which includes a new 500 kV terminal position at South Crystal substation, two associated 500 kV breakers, the re-termination of the existing 500/230 kV transformer #2, and required metering and protections equipment with an estimated cost of approximately $5.700 million. Projected cash flows for the Gemini Solar project are shown in Figure TP-24 below:

FIGURE TP-24
PROJECTED CASH FLOWS FOR GEMINI SOLAR GENERATION INTERCONNECTION

Gemini Solar Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$5,700,000	$0	$0	$0	$570,000	$570,000	$5,130,000

5. Apex Industrial Park 230 Kv Switchyard

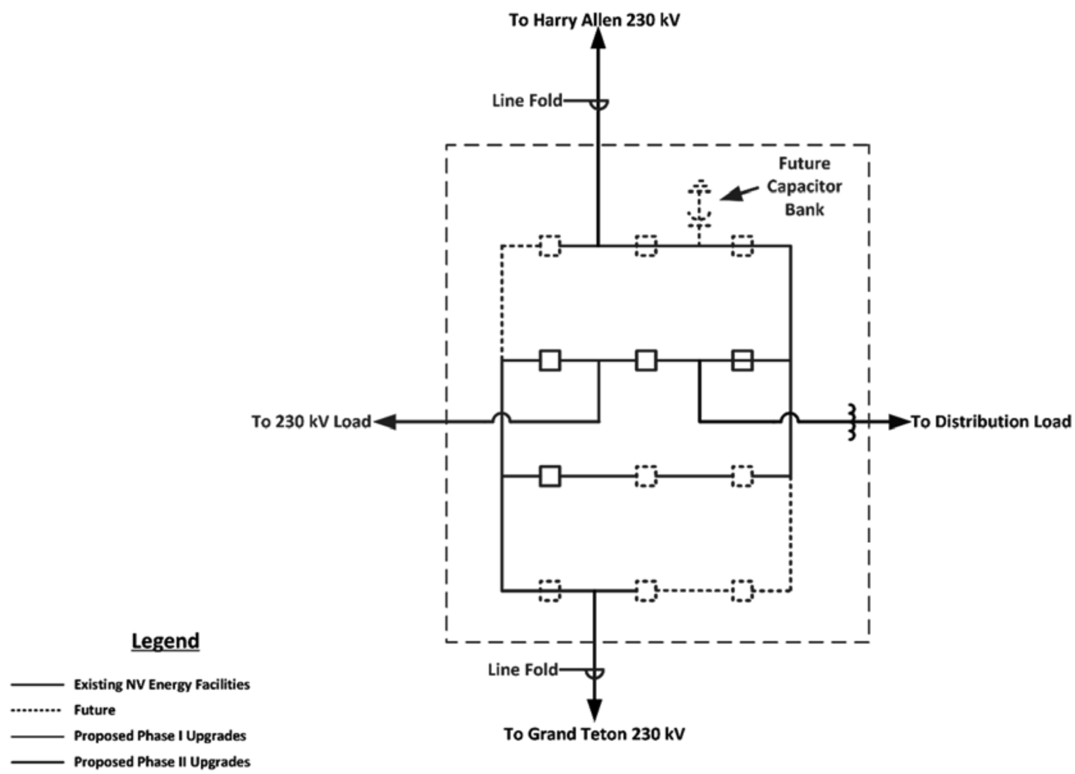
Nevada Power has analyzed the interconnection of a large load in the Apex Industrial park within the City of North Las Vegas. The proposed load is anticipated to take service at a transmission level voltage with an initial load of 13 MW that will eventually ramp to 30 MW. Two options were identified; a radial 138 kV line from Pecos Substation and the construction of a 230 kV switching station along the Harry Allen to Grand Teton 230 kV line. Nevada Power's transmission and distribution planning have identified the need for a new substation in the vicinity of the proposed load. Either a 138 kV or 230 kV substation could provide this service, however, the 138 kV would be single sourced while the 230 kV would be dual sourced. Additionally, the 230 kV system could accommodate more load growth and integrate better with the area for future planning. As a result, the Companies are proposing the construction of a new 230 kV switchyard on the south end of the Apex Industrial park that will initially serve 13 MW of load, but will be expandable to accommodate additional transmission interconnections as well as two distribution transformers.

There are thousands of acres of developable land in this geographical area and limited distribution resources. The existing distribution substations in the area are the Speedway and Gypsum substations, which are approximately eight miles apart. The proposed 230 kV switchyard is halfway between the two existing distribution substations. Without this propose 230 kV substation addition, long and costly distribution line extensions would be required to serve new loads in this area from the existing substations. Nevada Power is requesting approval to construct a new 230 kV switchyard that will be strategically located and expandable, with the ability to integrate into a future area master plan and serve nearby distribution load growth.

Construction Scope: Nevada Power is responsible for folding the existing 230 kV Harry Allen to Grand Teton 230 kV transmission line and construction of a four (4) breaker 230 kV transmission substation expandable for future transmission interconnections and future distribution transformers. The customer is responsible for the cost of the high voltage distribution line that serves its customer owned transformer as well as the substation site and on-site improvements. Figure TP-25 below depicts a single line diagram of the proposed Apex Industrial 230 kV switchyard.

FIGURE TP-25
ONE LINE DIAGRAM OF APEX INDUSTRIAL PARK 230 KV SWITCHYARD

NVEnergy	**Apex Industrial Park 230 kV Substation**	**5/31/2019**



Budget and Cost Responsibility: Nevada Power is responsible for the line fold of the 230 kV Harry Allen to Grand Teton 230 kV transmission line and the construction of a four (4) breaker 230 kV transmission substation and future distribution facilities, with an estimated cost of approximately $13.425 million. The customer is responsible for the cost of the high voltage distribution line that serves its customer owned transformer as well as the substation site and on-site improvements. A detailed description of the estimated cost responsibility is shown in Figure TP-26 and TP-27 below:

FIGURE TP-26
PROJECTED CASH FLOWS FOR APEX INDUSTRIAL PARK 230 KV SWITCHYARD

APEX INDUSTRIAL PARK - 230 kV SWITCHYARD					CASH FLOW PROJECTION		
	UPGRADE	CLASSIFICATION	IN SERVICE	ESTIMATED COST	2019	2020	2021
Communications	Fiber on Line Fold	TRANS	10/31/2021	360,000	18,000	252,000	90,000
	Switchyard	TRANS	10/31/2021	700,000	35,000	490,000	175,000
Lands	Land Rights	TRANS	10/31/2021	560,000	140,000	392,000	28,000
	Permit Requirements	TRANS	10/31/2021	200,000	50,000	140,000	10,000
Lines	HVD Line	CUSTOMER	10/31/2021	1,300,000	65,000	910,000	325,000
	Line Fold	TRANS	10/31/2021	2,300,000	115,000	1,610,000	575,000
Subs	New 230kV Switching Station	TRANS	10/31/2021	9,300,000	465,000	6,510,000	2,325,000
	Civil Improvements (Grading, Fence)	CUSTOMER	10/31/2021	1,900,000	95,000	1,330,000	475,000
PROJECT ESTIMATE				**16,620,000**	**983,000**	**11,634,000**	**4,003,000**
			CUSTOMER COST	**3,200,000**	160,000	2,240,000	800,000
	Note: Cost responsibility between Customer and Utility can change based on the final Rule 9 agreement.		UTILITY COST	**13,420,000**	823,000	9,394,000	3,203,000

FIGURE TP-27
PROJECTED CASH FLOWS FOR APEX INDUSTRIAL PARK 230 KV SWITCHYARD

Apex Industrial 230 kV Switching Station Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$13,420,000	$0	$0	$823,000	$9,394,000	$10,217,000	$3,203,000

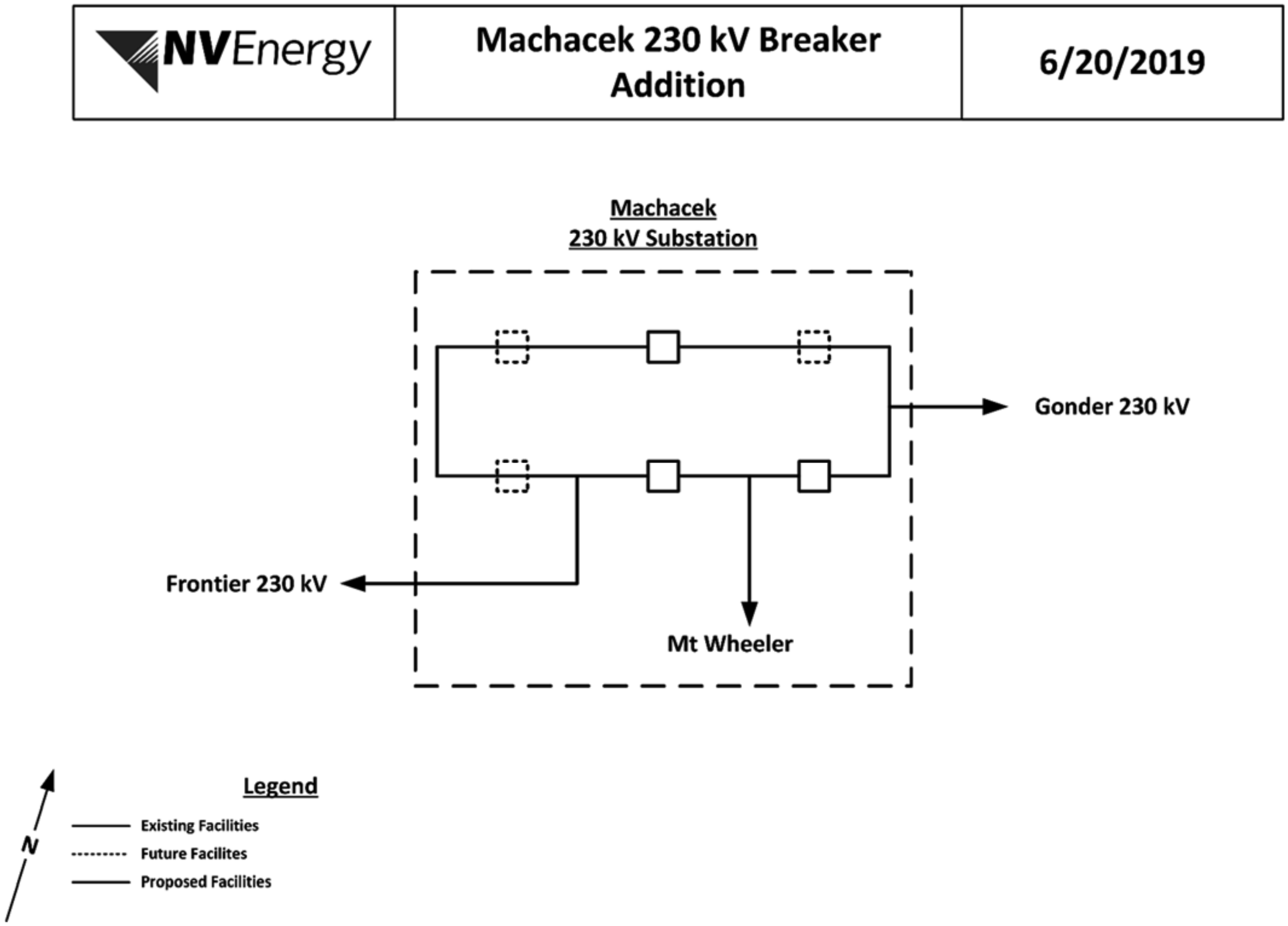
6. Machacek 230 Kv Breaker Addition

Sierra is proposing the addition of three 230 kV breakers at Machacek 230 kV substation, required to increase customer reliability and mitigate safety concerns with the operation of existing aging equipment. The existing configuration at Machacek 230 kV substation is such that a single contingency along the 115 mile Gonder to Frontier 230 kV line causes a loss of Machacek 230 kV substation and the entire Mt Wheeler 20 MW load it serves. The proposed configuration, with the addition of three breakers in a ring bus formation, will allow each segment of the 115 mile line (Gonder to Machacek 230 kV and Machacek to Frontier 230 kV), and the Mt Wheeler load to be operated independently, significantly increasing reliability to Machacek 230 kV substation and Mt. Wheeler load.

The proposed breaker addition also mitigates an existing safety hazard at the Machacek 230 kV substation. The existing motor operated switches require manual operation, due to their age and condition, and pose a safety concern for personnel from both Mt. Wheeler and NV Energy. In order to operate the existing switches, personnel has to physically manipulate the switch with an extension bar.

Construction Scope: Sierra is responsible for the construction at Machacek 230 kV substation required to add three 230 kV breakers in a ring bus formation. Figure TP-28 below depicts a single line diagram of the proposed Machacek 230 kV Breaker Addition.

FIGURE TP-28
ONE LINE DIAGRAM OF MACHACEK 230 KV BREAKER ADDITION



<u>Budget and Cost Responsibility</u>: Sierra is responsible for the cost of the breaker addition, which includes the addition of three 230 kV breakers, as well as associated protection and communication facilities. The project has an estimated cost of approximately $6.200 million. Projected cash flows for the Machacek 230 kV Breaker Addition are shown in Figure TP-29 below:

FIGURE TP-29
PROJECTED CASH FLOWS FOR MACHECEK 230 KV BREAKER ADDITION

Machacek 230 kV Breaker Addition Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$6,200,000	$0	$0	$0	$1,072,000	$1,072,000	$5,128,000

F. WestConnect Membership

The following information has not changed since the Companies filed their 2018 Joint IRP or its Second Amendment to the 2018 Joint IRP. Per NAC § 704.9385(3)(f), the Companies are required to describe their participation in regional planning organizations, as well as the role of these organizations in the Companies' transmission planning activities. In Docket No. 19-05003, the Companies are requesting permission to continue participation in WestConnect with funding of approximately $225,000 distributed equally over the three-year Action Plan period, as shown in Figure TP-30 below. The Companies are not requesting any approvals in this Third Amendment to the 2018 Joint IRP.

The Companies have participated in transmission planning activities associated with WestConnect since the 2015 formation of the organization, pursuant to the requirements laid forth in FERC Order No. 1000. WestConnect has a FERC-approved Planning Participation Agreement setting forth the rights and obligations of members who pay dues to WestConnect, stakeholders who participate in WestConnect open activities, and the Planning Management Committee that steers WestConnect.

FIGURE TP-30
WESTCONNECT MEMBERSHIP DUES (IN THOUSANDS)

	2019	**2020**	**2021**	**2019-2021** (3-Year Total)
NV Energy	**$225**	**$225**	**$225**	**$675**
TOTAL	**$225**	**$225**	**$225**	**$675**

G. Transmission Losses

The following information has not changed since the Companies filed their 2018 Joint IRP or its Second Amendment to the 2018 Joint IRP. NAC § 704.9385(3)(h) requires the Companies include in its Transmission Plan a description of efforts to reduce the impact of line losses on future resource requirements. The Companies' efforts to evaluate and mitigate line losses are ongoing. Line losses are calculated into the overall plan of service for load growth, selection of company-owned generation, independent power producer development, and renewable energy evaluations in order to develop the most cost effective facilities (*i.e.*, the impact of losses is evaluated in those cases where the Companies have the ability to select from various options).

H. Renewable Energy Zone Transmission Plan

The following information has not changed since the Companies filed their 2018 Joint IRP or the Second Amendment to the 2018 Joint IRP. In response to the requirements provided for in NAC § 704.9385(6) and NAC § 704.9489(5), regarding the development of transmission facilities to serve renewable energy zones within the State of Nevada, the Companies have prepared a Conceptual Renewable Energy Zone Transmission Plan ("REZTP" or "Plan").

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

The Companies did not produce new studies for the REZTP for this filing. There has been no interest by any parties outside the Companies to pursue any studies with respect to this plan. Upon a new identification of renewable energy zones by the Commission, or new interest by outside parties, the Companies will revisit the REZTP and update accordingly.

I. Federal Regulatory Filings

NAC § 704.9385(3)(g) requires the Companies include in the Transmission Plan a summary of the impacts of relevant orders issued by FERC. This information has not changed since the Companies filed their 2018 Joint IRP, Docket No. 18-06003, or the Second Amendment to the 2018 Joint IRP, Docket No. 19-05003.

J. Transmission Technical Appendices

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

Technical Appendix TRAN-1: Company 79-119 - Moapa Solar LGIA
Technical Appendix TRAN-2: Company 165 - Southern Bighorn Solar Re-SIS
Technical Appendix TRAN-3: Company 151 – Apex Solar LGIA
Technical Appendix TRAN-4: Gemini Solar – NTP System Impact Study

SECTION 6. ECONOMIC ANALYSIS

A. Overview

An economic analysis of supply-side alternatives was conducted and a Preferred Plan was selected from the set of cases. In this section, the following economic analysis topics will be covered:

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

B. Analysis Methodology

Loads & Resources Tables. The Companies' analysis of future resource requirements begins with the Loads and Resources ("L&R") tables. A long-term forecast of annual peak loads, 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 capacity position ("Open Position").

The Open Position is defined as any value resulting from the peak load plus planning reserves being greater than the sum of the peak planning capacities for all of the available supply-side and demand-side resources.

The Companies typically leave some Open Positions to be filled with market purchases for capacity and energy. In any year where there is an Open Position, the Companies assume the ability to secure 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. Additional discussion around the creation and use of the L&R tables is described in the Loads and Resources section (part G) of this Economic Analysis narrative.

Production Costs and Capital Expense Recovery Models. After developing the L&R tables, the Companies utilizes two economic models to evaluate each plan over the planning period. The first is a production cost model, PROMOD.[21] PROMOD computes overall production cost by performing hourly, chronological economic unit commitment and dispatch of the Companies' electric production resources and market purchases to satisfy load requirements in a least cost solution over the planning period. There are several key modeling assumptions made in performing PROMOD analysis. These include but are not limited to:

a) Planning period,
b) Joint system modeling,
c) Area configuration,
d) Hourly load forecast,
e) Market fundamentals,
f) Existing generation operating characteristics (including fixed costs),
g) New generation operating characteristics (including fixed costs),
h) Operating reserves,
i) Renewable energy modeling,
j) Purchase power agreements, and
k) Transmission limits.

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

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

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

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

Scenario Analysis. The base assumptions for this filing are a base (or mid-level) load forecast, base (or mid-level) fuel and purchase power price forecast, and a mid-level carbon price assumption. For this filing, the Companies have conducted sensitivities around the load with an "all eligible" case – which assumes all customers eligible to utilize a new electric provider under NRS Chapter 704B become distribution-only service customers.

The scenario analysis shows how the PWRR results would change under the different sensitivities. Figure EA-1 below shows the scenarios performed on each plan. The production costs, capital costs, and total PWRR results for all the scenarios run are found in Technical Appendix Items ECON-2 and ECON-3.

FIGURE EA-1:
SENSITIVITIES CONDUCTED FOR ECONOMIC ANALYSIS

Scenario	Load	Fuel	Carbon
1*	Base	Base	MidC
2	All eligible	Base	MidC

* Base Assumptions

C. Updates To Key Modeling Assumptions

Area Configuration. PROMOD utilizes an area configuration in order to assign resources and load to specific areas and to capture transmission use between areas. The area configuration used in this analysis reflects updates from the diagram presented in the 2018 Joint IRP, Docket No. 18-06003. 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 Item ECON-5.

Hourly Load Forecast. The base case load forecast used in the economic analysis is consistent with the forecast filed in Docket No. 19-05003, the Second Amendment to the 2018 Joint IRP with one exception. In the all eligible case DSM savings changed due to lower sales. The load forecast is described in Section 3 of the narrative found in Volume 1 and is supported in Technical Appendix LF-1 found in Volume 2 of Docket No. 19-05003.

Market Fundamentals. The Companies' base case market fundamentals analysis and price forecasts have not changed from the forecast approved by the Commission in Docket No. 18-06003.

Existing Generation Operating Characteristics and Fixed Costs. The operating characteristics and costs for existing generators have been updated from those used in the Companies' 2018 IRP, Docket No. 18-06003. Operating characteristics assumptions, including fixed operations and maintenance expense ("O&M"), of the Companies' generation fleet are shown in confidential Technical Appendix Item GEN-1.

Operating Reserves. The methodology to calculate operating reserves has not changed from the Companies' 2018 IRP, Docket No. 18-06003, but the addition of new resources causes different reserve requirements. The operating reserve calculation is presented in Technical Appendix Item ECON-4.

Renewable Energy. The assumptions for modeling renewable energy have not changed, but Nevada's renewable portfolio requirements have. Please refer to the Renewable Energy Section of this Supply Plan for a description of the standard modeled for this analysis.

Transmission Limits. Transmission limits, including access to external markets as well as limits over ON Line were modeled in accordance with Technical Appendix Item ECON-5. Although PROMOD is not a transmission flow model, all transmission capacity constraints are included in the model and any projected flows based on economics are not allowed to exceed these capacities.

Battery Modeling. In Docket No. 18-06003, the Commission approved the contracts for three solar projects with associated battery energy storage systems ("BESS"). The Companies modeled each of these solar/BESS systems as two distinct transactions – 1) the solar facility with a unique hourly generation profile, and 2) a battery that can charge from any resource and discharge whenever economic. This methodology was satisfactory with a few, small-scale batteries in the system, but posed challenges when applied to higher penetrations of larger batteries. Specifically, modeling two transactions did not require the battery to charge from the associated solar arrays causing PROMOD to report excess generation when none existed. The Companies updated its model of solar/BESS systems by creating a charge/discharge hourly shape for each battery and combining it with the hourly shape of the associated solar facility.

Negative Load. Renewable resources are generally modeled as load modifying transactions and reflect the expected hourly output profiles. That is, the projected hourly output from any renewable resource is subtracted from the expected hourly load. In some hours (*e.g.,* in low load in shoulder or off-seasons), the non-dispatchable output from renewable resources exceeds the forecasted load. This results in a negative number which will cause PROMOD to stop processing. To avoid negative load conditions and to quantify excess energy volumes, the Companies have modeled a zero-cost firm sale and an off-setting zero-cost generator in PROMOD. The zero-cost sale is interpreted by PROMOD as in increase in the load, and ensures that negative loads are not calculated. The zero-cost generator serves the zero-cost sale *unless* the sale is being served by the excess renewable energy. The difference between the sales energy and the generator energy is the excess renewable energy. This excess is quantified as *dump energy* in the PROMOD output.

CER Inputs. The CER captures the capital costs of utility-owned resources, such as future generators or transmission infrastructure to be constructed and owned by the Companies. The timing of the project, cash flows during the construction period, AFUDC, and project book lives and tax lives are all factors into the final annual revenue requirement that is captured in the PWRR calculation. Work papers associated with capital projects can be found in Technical Appendix Item ECON-2.

D. Plan Development

In 2016, NV Energy's approach to integrated resource planning shifted from a long-run to a short-term focus. The Secretary of State certified Question 3 in July 2016; among other things, Question 3 would have amended the Nevada Constitution to "prohibit the grant of monopolies and exclusive franchises for the generation of electricity." This measure, which was approved once by voters in 2016, created significant uncertainty— that disrupted the resource planning process.

The Commission recognized this uncertainty in Docket Nos. 16-07001, 16-07007 & 16-08027. "The Commission's decision to deem inadequate the acquisition of South Point was primarily based upon the availability of power on the open market and the uncertainty of the future of Nevada's energy policies."[22] The order continues, pursuing "a more economic short-term procurement strategy until additional long-term certainty about Nevada's energy market can be ascertained."[23] The record in that proceeding was "replete with references to" Question 3 and the "uncertainty cause by [Question 3] or its potential to create stranded resource."[24] In short, this uncertainty and the voters' initial "overwhelming support for [Question 3]" caused shifted the focus of resource planning: "Until there is greater certainty regarding . . . [the Companies acquisition of resources] to cover the open positions of SPPC's and NPC's customers shall be short-term in nature (less than five years) and consistent with the energy policies of the State."[25]

In November 2018, the Companies issued the 2019 Renewable RFP as additional certainty "regarding" the nature of Nevada's energy markets began to come into focus. In November 2018, voters rejected Question 3. The 80th Session of the Nevada Legislature increased Nevada's RPS and established an aspirational goal of achieving carbon-neutrality in the energy sector by 2050.

The results of the 2019 Renewable RFP and the Preferred Plan provide an opportunity to refocus integrated resource planning on long-term objectives: adding cost-effective renewable resources while, at the same time reducing carbon emissions and the Companies' Open Positions through long-term (instead of short-run) commitments.[26] The long-term obligations incorporated into the Preferred Plan enhance reliability, reduce risk, improve price stability through fixed pricing and increase the diversity of the Companies' supply-side portfolio. Equally important, the Preferred Plan provides a solid foundation for developing alternative pricing plans that existing and new large commercial and industrial customer's value, while securing resources that reduce the PWRR in a way that also benefits mass market (*i.e.*, residential and small commercial) customers.

After it received the results from the 2019 Renewable RFP, the Companies' developed the following five expansion plans:

[22] Docket Nos. 16-07001, 16-07007 & 16-08027, Order on Reconsideration at ¶ 44 (iss. Feb. 16, 2017).
[23] Id. ¶ 47.
[24] Id. ¶ 51.
[25] Docket Nos. 16-07001, 16-07007 & 16-08027, Final Order at ¶ 107 (iss. Feb. 16, 2017).
[26] While the Preferred Plan pivots, shifting again to long-term commitments to reduce the Open Position, it relies on new resources and thus does not reduce the Open Position through long-term commitments until the new resources begin commercial operation.

All Placeholder Case: This case satisfies NV Energy's entire RPS compliance only using future renewable placeholders.

Moapa Case: This case models EDF's Moapa plant (200 MW Moapa Solar PV facility with integrated battery energy storage capable of discharging 75 MW of real power and energy storage capacity of 375 MWh) and future renewable placeholders. For this case, it was assumed Moapa capacity and energy would be shared with 70 percent of the costs and energy allocated to Sierra and 30 percent to Nevada Power.

SBS Case: This case models 8minutenergy's Southern Bighorn Solar plant (300 MW Southern Bighorn Solar Farm PV facility with integrated battery energy storage capable of discharging 135 MW of real power and energy storage capacity of 540 MWh 300 MW of solar PV resource with 135 MW of battery energy storage) and future renewable placeholders. For this case, it was assumed Southern Bighorn Solar capacity and energy would be shared with 40 percent of the costs and energy allocated to Sierra and 60 percent to Nevada Power.

Arevia Case: This case models Arevia's Gemini plant (690 MW Gemini Solar PV facility with integrated battery energy storage capable of discharging 380 MW of real power and energy storage capacity of 1,416 MWh) and future renewable placeholders. Future renewable placeholders are used to meet all of Sierra's RPS requirements.

M_S_A Case: This case models all three plants (Gemini, Southern Bighorn, and Moapa) and future renewable placeholders. This case specifically adds 1,190 MW of solar PV with integrated battery energy storage capable of discharging 590 MW of real power and 2,331 MWh of energy storage capacity to NV Energy's supply portfolio.

Renewable Placeholders (Beyond the Action Plan Period). The allocation of the proposed contracts and future renewable placeholders were adjusted where necessary to ensure that each plan met or exceeded compliance with Nevada's RPS through the planning period.

Figures EA-2 through EA-5 show the renewable resource additions by company for each plan for the base and "all eligible" load scenarios, respectively.

FIGURE EA-2
BASE LOAD – NEVADA POWER RENEWABLE RESOURCE ADDITIONS

Nevada Power Renewable Placeholders by Case - BASE load				
All Placeholder	Moapa	SBS	Arevia	MSA (all 3 contracts)
	60 MW Moapa (30%) - 2022			60 MW Moapa (30%) - 2022
		180 MW SBS (60%) - 2023	690 MW Gemini (100%) - 2023	180 MW SBS (60%) - 2023
				690 MW Gemini (100%) - 2023
275 MW PV - 2028				
475 MW PV - 2029	575 MW PV - 2029			
825 MW PV - 2030	925 MW PV - 2030	1150 MW PV - 2030		
		225 MW PV - 2031		
	50 MW PV - 2032	50 MW PV - 2032		
100 MW Geo - 2033	100 MW Geo - 2033	100 MW Geo - 2033		
250 MW PV - 2033	200 MW PV - 2033	175 MW PV - 2033	700 MW PV - 2033	
			100 MW Geo - 2034	
		25 MW PV - 2034	400 MW PV - 2034	
25 MW PV - 2035	50 MW PV - 2035	50 MW PV - 2035	75 MW PV - 2035	100 MW Geo - 2035
				925 MW PV - 2036
125 MW PV - 2037	125 MW PV - 2037	125 MW PV - 2037	100 MW PV - 2037	125 MW PV - 2037
75 MW PV - 2038	50 MW PV - 2038	50 MW PV - 2038	100 MW PV - 2038	75 MW PV - 2038
50 MW PV - 2039	75 MW PV - 2039	75 MW PV - 2039	50 MW PV - 2039	50 MW PV - 2039
50 MW PV - 2040	25 MW PV - 2040	25 MW PV - 2040	25 MW PV - 2040	50 MW PV - 2040
125 MW PV - 2041	150 MW PV - 2041	150 MW PV - 2041	175 MW PV - 2041	150 MW PV - 2041
50 MW PV - 2042	25 MW PV - 2042	50 MW PV - 2042	25 MW PV - 2042	25 MW PV - 2042
	25 MW PV - 2043		25 MW PV - 2043	25 MW PV - 2043
100 MW PV - 2044	75 MW PV - 2044	75 MW PV - 2044	75 MW PV - 2044	100 MW PV - 2044
	50 MW PV - 2045	25 MW PV - 2045	25 MW PV - 2045	25 MW PV - 2045
75 MW PV - 2046	25 MW PV - 2046	75 MW PV - 2046	75 MW PV - 2046	50 MW PV - 2046
650 MW PV - 2047	675 MW PV - 2047	625 MW PV - 2047	650 MW PV - 2047	650 MW PV - 2047
		25 MW PV - 2048		75 MW PV - 2048

FIGURE EA-3
BASE LOAD – SIERRA RENEWABLE RESOURCE ADDITIONS

Sierra Renewable Resources by Case - BASE load				
All Placeholder	Moapa	SBS	Arevia	MSA (all 3 contracts)
	140 MW Moapa (70%) - 2022			140 MW Moapa (70%) - 2022
		120 MW SBS (40%) - 2023		120 MW SBS (40%) - 2023
75 MW PV - 2024			75 MW PV - 2024	
200 MW PV - 2025		25 MW PV - 2025	200 MW PV - 2025	
75 MW PV - 2026	25 MW PV - 2026	175 MW PV - 2026	75 MW PV - 2026	
300 MW PV - 2027	475 MW PV - 2027	300 MW PV - 2027	300 MW PV - 2027	
25 MW PV - 2028		25 MW PV - 2028	25 MW PV - 2028	275 MW PV - 2028
75 MW PV - 2029	100 MW PV - 2029	75 MW PV - 2029	75 MW PV - 2029	150 MW PV - 2029
225 MW PV - 2030	225 MW PV - 2030	250 MW PV - 2030	225 MW PV - 2030	275 MW PV - 2030
25 MW PV - 2031			25 MW PV - 2031	
	25 MW PV - 2032	25 MW PV - 2032		
25 MW PV - 2034			25 MW PV - 2034	25 MW PV - 2034
	25 MW PV - 2035			
25 MW PV - 2037		50 MW PV - 2037	25 MW PV - 2037	25 MW PV - 2037
50 MW PV - 2038	75 MW PV - 2038	25 MW PV - 2038	50 MW PV - 2038	75 MW PV - 2038
	25 MW PV - 2039	50 MW PV - 2039		
25 MW PV - 2040			25 MW PV - 2040	
25 MW PV - 2041			25 MW PV - 2041	50 MW PV - 2041
	25 MW PV - 2042			
		25 MW PV - 2043		
25 MW PV - 2044	25 MW PV - 2044		25 MW PV - 2044	
75 MW PV - 2045	100 MW PV - 2045	125 MW PV - 2045	75 MW PV - 2045	100 MW PV - 2045
100 MW PV - 2046	75 MW PV - 2046	50 MW PV - 2046	100 MW PV - 2046	100 MW PV - 2046
50 MW Geo - 2047	50 MW Geo - 2047	50 MW Geo - 2047	100 MW Geo - 2047	100 MW Geo - 2047
225 MW PV - 2047	200 MW PV - 2047	250 MW PV - 2047	75 MW PV - 2047	75 MW PV - 2047
	175 MW PV - 2048			150 MW PV - 2048

FIGURE EA-4
ALL ELIGIBLE LOAD – NEVADA POWER RENEWABLE RESOURCE ADDITIONS

Nevada Power Renewable Placeholders by Case - ALL ELIGIBLE load				
All Placeholder	Moapa	SBS	Arevia	MSA (all 3 contracts)
	60 MW Moapa (30%) - 2022			60 MW Moapa (30%) - 2022
		180 MW SBS (60%) - 2023	690 MW Gemini (100%) - 2023	180 MW SBS (60%) - 2023
				690 MW Gemini (100%) - 2023
775 MW PV - 2031				
425 MW PV - 2032	275 MW PV - 2032			
100 MW Geo - 2033	100 MW Geo - 2033	100 MW Geo - 2033		
200 MW PV - 2033	850 MW PV - 2033	700 MW PV - 2033		
	25 MW PV - 2034	450 MW PV - 2034		
50 MW PV - 2035	50 MW PV - 2035	25 MW PV - 2035		
		50 MW PV - 2036		
			100 MW Geo - 2037	
125 MW PV - 2037	100 MW PV - 2037	100 MW PV - 2037	375 MW PV - 2037	
75 MW PV - 2038	75 MW PV - 2038	75 MW PV - 2038	600 MW PV - 2038	
50 MW PV - 2039	75 MW PV - 2039	25 MW PV - 2039	25 MW PV - 2039	
25 MW PV - 2040		75 MW PV - 2040	50 MW PV - 2040	
200 MW PV - 2041	225 MW PV - 2041	175 MW PV - 2041	200 MW PV - 2041	1250 MW PV - 2041
25 MW PV - 2042		25 MW PV - 2042	50 MW PV - 2042	50 MW PV - 2042
	50 MW PV - 2043	25 MW PV - 2043		25 MW PV - 2043
100 MW PV - 2044	50 MW PV - 2044	75 MW PV - 2044	75 MW PV - 2044	75 MW PV - 2044
25 MW PV - 2045	50 MW PV - 2045	25 MW PV - 2045	25 MW PV - 2045	25 MW PV - 2045
50 MW PV - 2046	50 MW PV - 2046	75 MW PV - 2046	100 MW PV - 2046	75 MW PV - 2046
650 MW PV - 2047	650 MW PV - 2047	625 MW PV - 2047	625 MW PV - 2047	650 MW PV - 2047
	150 MW PV - 2048	75 MW PV - 2048		50 MW PV - 2048

FIGURE EA-5
ALL ELIGIBLE LOAD – SIERRA RENEWABLE RESOURCE ADDITIONS

Sierra Renewable Resources by Case - ALL ELIGIBLE				
All Placeholder	Moapa	SBS	Arevia	MSA (all 3 contracts)
	140 MW Moapa (70%) - 2022			140 MW Moapa (70%) - 2022
		120 MW SBS (40%) - 2023		120 MW SBS (40%) - 2023
425 MW PV - 2031			425 MW PV - 2031	
25 MW PV - 2032	400 MW PV - 2032	200 MW PV - 2032	25 MW PV - 2032	
25 MW PV - 2033	25 MW PV - 2033	200 MW PV - 2033	25 MW PV - 2033	
	25 MW PV - 2035	25 MW PV - 2035		
25 MW PV - 2037			25 MW PV - 2037	
50 MW PV - 2038	50 MW PV - 2038	50 MW PV - 2038	50 MW PV - 2038	
25 MW PV - 2039	25 MW PV - 2039	50 MW PV - 2039	25 MW PV - 2039	
25 MW PV - 2040	25 MW PV - 2040		25 MW PV - 2040	
	25 MW PV - 2042			325 MW PV - 2042
		25 MW PV - 2043		25 MW PV - 2043
25 MW PV - 2044			25 MW PV - 2044	
125 MW PV - 2045	100 MW PV - 2045	125 MW PV - 2045	125 MW PV - 2045	75 MW PV - 2045
50 MW PV - 2046	100 MW PV - 2046	50 MW PV - 2046	50 MW PV - 2046	100 MW PV - 2046
50 MW Geo - 2047	50 MW Geo - 2047	50 MW Geo - 2047	100 MW Geo - 2047	100 MW Geo - 2047
225 MW PV - 2047	200 MW PV - 2047	250 MW PV - 2047	75 MW PV - 2047	100 MW PV - 2047
	50 MW PV - 2048	25 MW PV - 2048		125 MW PV - 2048

<u>Conventional Placeholders (Beyond the Action Plan Period).</u> Future conventional placeholders have been added to each plan to maintain a similar level of dependence on market purchases between cases. These placeholder include longer-term (>3 year), summer-only purchases, called TOLL, and replacements for existing conventional generators.[27] Conventional placeholders for the Base load forecast is shown in Figure EA-6 and for the All-Eligible forecast in Figures EA-7.

FIGURE EA-6
CONVENTIONAL RESOURCE PLACEHOLDERS - BASE LOAD

ALL PLACEHOLDER				
UNIT	SIZE	START	LOCATION	TERM
Summer Toll	400 MW	2023	south	15
Summer Toll	265 MW	2026	north	6
1x1 CC	358 MW	2029	north	35
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
2 - CTs	84 MW	2035	north	30
1x1 CC	382 MW	2035	south	35
9 - CTs	90 MW	2039	south	30
1x1 CC	382 MW	2040	south	35
2x1 CC	900 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	30
2x1 CC	839 MW	2044	north	35

MOAPA				
UNIT	SIZE	START	LOCATION	TERM
Summer Toll	400 MW	2023	south	15
Summer Tol	265 MW	2026	north	6
1x1 CC	358 MW	2029	north	35
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
2 - CTs	84 MW	2035	north	30
1x1 CC	382 MW	2035	south	35
9 - CTs	90 MW	2039	south	30
1x1 CC	382 MW	2040	south	35
2x1 CC	900 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	30
2x1 CC	839 MW	2044	north	35

SBS				
UNIT	SIZE	START	LOCATION	TERM
Summer Toll	400 MW	2023	south	15
Summer Tol	265 MW	2026	north	6
1x1 CC	358 MW	2029	north	35
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
2 - CTs	84 MW	2035	north	30
1x1 CC	382 MW	2035	south	35
9 - CTs	90 MW	2039	south	30
1x1 CC	382 MW	2040	south	35
2x1 CC	900 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	30
2x1 CC	839 MW	2044	north	35

[27] <u>See</u> Nev. Admin. Code § 704.9113 (defining long-term power purchase agreements as any contract, including a multiple seasonable contract, with a term of more than 3 years).

AREVIA				
UNIT	SIZE	START	LOCATION	TERM
Summer Toll	400 MW	**2030**	south	**10**
Summer Tol	265 MW	2026	north	6
1x1 CC	358 MW	2029	north	35
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
2 - CTs	84 MW	2035	north	30
1x1 CC	382 MW	2035	south	35
9 - CTs	90 MW	2039	south	30
1x1 CC	382 MW	2040	south	35
2x1 CC	900 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	30
2x1 CC	839 MW	2044	north	35

M_S_A				
UNIT	SIZE	START	LOCATION	TERM
Summer Toll	400 MW	**2032**	south	**8**
Summer Tol	265 MW	2026	north	6
1x1 CC	358 MW	2029	north	35
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
2 - CTs	84 MW	2035	north	30
1x1 CC	382 MW	2035	south	35
9 - CTs	90 MW	2039	south	30
1x1 CC	382 MW	2040	south	35
2x1 CC	900 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	30
2x1 CC	839 MW	2044	north	35

FIGURE EA-7
CONVENTIONAL RESOURCE PLACEHOLDERS – ALL ELIGIBLE LOAD

ALL PLACEHOLDER				
UNIT	SIZE	START	LOCATION	TERM
1x1 CC	358 MW	2029	north	35
Summer Toll	400 MW	2030	south	15
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
1x1 CC	382 MW	2035	south	35
CT	84 MW	2035	north	30
9 - CTs	90 MW	2039	south	30
2x1 CC	900 MW	2040	south	35
1x1 CC	382 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	35
2x1 CC	839 MW	2044	north	35

MOAPA				
UNIT	SIZE	START	LOCATION	TERM
1x1 CC	358 MW	2029	north	35
Summer Toll	400 MW	2030	south	15
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
1x1 CC	382 MW	2035	south	35
CT	84 MW	2035	north	30
9 - CTs	90 MW	2039	south	30
2x1 CC	900 MW	2040	south	35
1x1 CC	382 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	35
2x1 CC	839 MW	2044	north	35

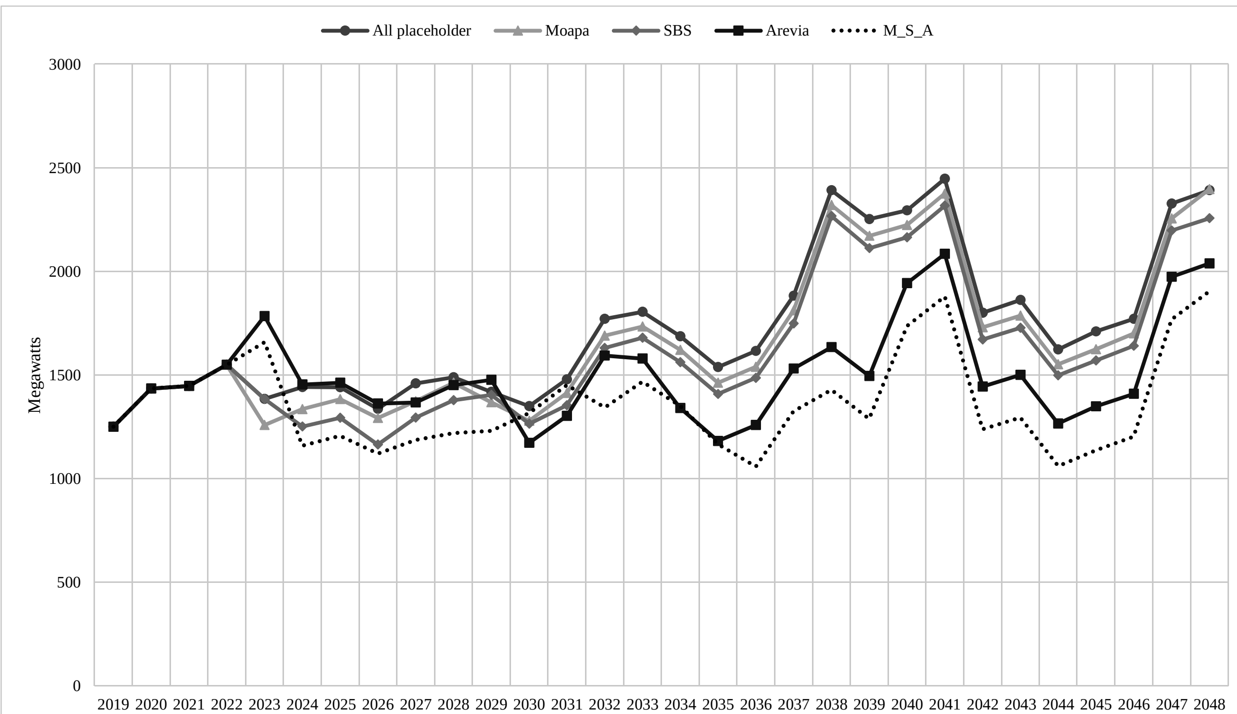
SBS				
UNIT	SIZE	START	LOCATION	TERM
1x1 CC	358 MW	2029	north	35
Summer Toll	400 MW	2030	south	15
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
1x1 CC	382 MW	2035	south	35
CT	84 MW	2035	north	30
9 - CTs	90 MW	2039	south	30
2x1 CC	900 MW	2040	south	35
1x1 CC	382 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	35
2x1 CC	839 MW	2044	north	35

AREVIA				
UNIT	SIZE	START	LOCATION	TERM
1x1 CC	358 MW	2029	north	35
Summer Toll	400 MW	**2032**	south	**8**
CT	**84 MW**	**2032**	**north**	**30**
1x1 CC	382 MW	2034	south	35
1x1 CC	382 MW	2035	south	35
1x1 CC	**358 MW**	**2035**	**north**	**35**
9 - CTs	90 MW	2039	south	30
2x1 CC	900 MW	2040	south	35
1x1 CC	382 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	35
2x1 CC	839 MW	2044	north	35

M_S_A				
UNIT	SIZE	START	LOCATION	TERM
1x1 CC	358 MW	2029	north	35
Summer Toll	400 MW	**2032**	south	**8**
1x1 CC	358 MW	2032	north	35
1x1 CC	382 MW	2034	south	35
1x1 CC	382 MW	2035	south	35
CT	84 MW	2035	north	30
9 - CTs	90 MW	2039	south	30
2x1 CC	900 MW	2040	south	35
1x1 CC	382 MW	2040	south	35
2 - 2x1 CCs	900 MW	2042	south	35
2x1 CC	839 MW	2044	north	35

Open Positions and Open Position Capacity Costs. Figure EA-8 shows the Open Positions of each plan under the Base Load sensitivity. As explained in the Load Forecast and Market Fundamentals volume, the purchase power price forecast includes a monthly capacity charge associated with firm capacity purchases. This capacity charge is reflected in the pricing in each plan and is a function of the size of the Open Positions for each case. As has been described, each of the plans has a slightly different Open Position but attempts are made to make the resource additions being evaluated in each case approximately the same size so that the reliability of each case, dependence on the market for capacity and energy, and the capacity cost of each case are similar.

FIGURE EA-8
OPEN POSITION FOR EACH RESOURCE PLAN CASE



E. Economic Analysis Results

The results of the economic analysis follows and begins with Figure EA-9 which contains the PWRRs for all scenarios over 20 and 30 years respectively. A discussion of the key findings from the results follows the figure.

FIGURE EA-9
20- AND 30-YEAR PWRRs FOR ALL CASES AND SENSITIVITIES

20-year PWRR ($ millions) by Scenario		
	Base Load	All Eligible
	Base Fuel	Base Fuel
	MC	MC
MSA	$ 18,404	$ 15,817
Arevia	$ 18,510	$ 15,864
SBS	$ 18,571	$ 15,926
Moapa	$ 18,609	$ 15,958
All Placeholder	$ 18,662	$ 15,987

30-year PWRR ($ millions) by Scenario		
	Base Load	All Eligible
	Base Fuel	Base Fuel
	MC	MC
MSA	$ 24,340	$ 20,903
Arevia	$ 24,528	$ 21,022
SBS	$ 24,660	$ 21,167
Moapa	$ 24,722	$ 21,218
All Placeholder	$ 24,811	$ 21,248

20-year PWRR Differential ($ millions) by Scenario		
	Base Load	All Eligible
	Base Fuel	Base Fuel
	MC	MC
MSA	$ -	$ -
Arevia	$ 106	$ 47
SBS	$ 168	$ 109
Moapa	$ 205	$ 142
All Placeholder	$ 258	$ 170

30-year PWRR Differential ($ millions) by Scenario		
	Base Load	All Eligible
	Base Fuel	Base Fuel
	MC	MC
MSA	$ -	$ -
Arevia	$ 188	$ 119
SBS	$ 320	$ 264
Moapa	$ 382	$ 315
All Placeholder	$ 471	$ 344

20-year PWRR Ranking by Scenario		
	Base Load	All Eligible
	Base Fuel	Base Fuel
	MC	MC
MSA	1	1
Arevia	2	2
SBS	3	3
Moapa	4	4
All Placeholder	5	5

30-year PWRR Ranking by Scenario		
	Base Load	All Eligible
	Base Fuel	Base Fuel
	MC	MC
MSA	1	1
Arevia	2	2
SBS	3	3
Moapa	4	4
All Placeholder	5	5

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

- The M_S_A case provides the lowest overall cost for the Companies' customers in both the 20- and 30-year analysis in the base load, base fuel and mid-carbon scenario (*i.e.*, Scenario 1).

- Likewise, the M_S_A case also provides the lowest overall cost for the Companies' customers in Scenario 2.[28]

- The M_S_A case has the lowest carbon dioxide emissions over the 30-year study period.

F. Selection Of The Preferred Plan

The Companies selected the M_S_A Case as the Preferred Plan. The case has the lowest PWRR, the lowest carbon emissions and the highest percentage of long-term obligations providing capacity resources. The long-term obligations incorporated into the Preferred Plan enhance reliability, reduce risk, improve price stability through fixed pricing and increase the diversity of the Companies' supply-side portfolio. The Preferred Plan provides a solid foundation for developing alternative pricing plans that existing and new large commercial and industrial customer's value, while securing resources that reduce the PWRR in a way that also benefits mass market (*i.e.*, residential and small commercial) customers.

The Preferred Plan is consistent with Nevada's energy policies. The Preferred Plan includes an estimated $3.86 billion progressive investment in Nevada,[29] yielding, during construction, a temporary workforce increase 3,275 positions. The three long-term contracts secure an estimated 40 long-term jobs with a total payroll impact of $100 million over the lives of the three renewable projects. Finally, the Preferred Plan positions the Companies to meet increases in the RPS. The Preferred Plan better positions NV Energy to help Nevada become "a leading producer and consumer of clean renewable energy." The plan, in short, delivers the economic, health and environmental benefits that Nevada's energy policy makers expect.

G. Loads And Resources Tables

NAC § 704.945 requires a table of loads and resources for each alternative plan analyzed. For the Preferred Plan, the 30-year projection of peak load, planning reserve requirements, total required resources, existing and future supply-side resources, and existing and future demand-side resources is provided in Figure EA-10. L&R tables for each Company under the alternative plans, are provided in Technical Appendix Item ECON-1.

Overview. Consistent with the 2018 Joint IRP, the L&R tables have been combined for this joint IRP. The L&R tables provide the forecasted peak load (in MW) for the peak hour of the peak day of the year ("Peak Load"), the Peak Load plus a planning reserve requirement ("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

[28] Lower total cost does not necessarily translate to lower overall prices for electricity, as the scope of the Companies' operations is reduced in Scenario 2.
[29] In 2019 dollars.

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 balancing authority area for customers that supply their own supply-side and demand-side resources, 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.

Planning reserve margins of approximately 13 percent are added to the Peak Load to determine the Required Resources. This level of planning reserve is the sum of the planning reserves for Nevada Power and Sierra. Each Company's planning reserve margin was selected to achieve a loss of load probability of no more than 1 day in 10 years. The planning reserve margins in this joint filing help ensure that the Companies plan for sufficient supply-side resources and demand-side resources to meet the total requirements of native load customers.

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

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 Item GEN-1. The capacity of future conventional placeholders can be found in Technical Appendix Item GEN-2 found in Volume 11 of Docket No. 18-06003. The capacity for conventional generators varies depending on the time of the year and is categorized as winter capacity, summer capacity, or peak capacity. The peak capacity value is used for existing conventional generators on the L&R tables. For PPAs for conventional generation, the contractually agreed upon capacity during the Peak Load hour is used.

For existing non-intermittent rewewable energy resources (*e.g.*, geothermal and hydro) the capacity reflected on the L&R tables is based on the peak hour generation commitment in the energy supply table in the applicable PPAs. The standard PPA energy supply table provides average hourly generator forecasts for each month of the year. The value used for the L&R tables is the hour ending 17:00 (5 p.m.) in July. In some cases, historical performance regarding the amount of generation capacity that can be reliably provided during such periods is used to adjust the value in the energy supply table. The capacity that can be counted on during the Peak Load hour is typically lower than the nameplate capacity of the generator. For existing wind resources, the capacity value of the resource as reflected on the L&R table is 10 percent of nameplate capacity. For existing solar PV resources, the capacity value of the resource as reflected on the L&R table is based on the Effective Load Carrying Capability ("ELCC") study conducted by the Companies in compliance with Directive 8 in Docket No. 15-07004. The report was attached as Technical Appendix ECON-11 in Docket No. 18-06003. The L&R value for all (existing and new) solar PV varies inversely with the amount of solar PV penetration on the system. That is, as the total aggregate amount of nameplate solar PV capacity increases, the percent of nameplate capacity decreases. The percentage begins in the most current year as 33 percent of nameplate capacity. As the amount of solar PV penetration on the system increases, the percent of nameplate capacity decreases, the lowest being 20 percent.

For future non-intermittent renewable placeholders, energy supply tables for current PPAs sourced from similar technologies and sizes are used to determine the peak capacity during Peak Load in the L&R tables. The capacity value for batteries reflected on the L&R is the lesser of the contractual capacity value and the discharge energy divided by four. In the case of intermittent renewable generation, the same adjustment is made to the future placeholders as is made for existing PPAs for these types of generation. A declining capacity value of 33 to 20 percent of the nameplate rating is assigned for purposes of preparing the L&R tables for future solar PV.

The L&R tables show existing contracts expiring per the contract expiration date. Renewable placeholder contracts are added as needed to meet requirements for RPS compliance.

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 Tables. Figure EA-10 provides the L&R table for the Preferred Plan under the Base Load scenario. There have been no substative changes to the L&R table since NV Energy's 2018 IRP, Docket No. 18-06003.

FIGURE EA-10
L&R TABLE
M_S_A CASE
(2019-2038)

NV Energy
LOADS AND RESOURCES TABLE
Current_Moapa_SBS_Arevia

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Peak	7,725	7,839	7,984	7,965	8,171	8,294	8,411	8,494	8,535	8,695	8,793	8,898	9,011	9,115	9,141	9,317	9,426	9,563	9,654	9,707
DSM	49	97	147	196	245	294	344	394	445	496	547	599	651	703	755	807	859	912	965	1,018
Private Generation	39	75	107	127	137	145	152	157	161	165	170	175	179	183	188	192	197	200	205	210
Avoided Capacity	177	199	229	239	236	241	253	257	272	265	267	268	278	280	291	281	285	293	284	305
Forecast System Peak	7,459	7,468	7,501	7,404	7,553	7,615	7,662	7,687	7,656	7,769	7,809	7,856	7,903	7,950	7,908	8,037	8,085	8,157	8,200	8,175
Sales Obligations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NET System Peak	7,459	7,468	7,501	7,404	7,553	7,615	7,662	7,687	7,656	7,769	7,809	7,856	7,903	7,950	7,908	8,037	8,085	8,157	8,200	8,175
Planning Reserves (13%)	950	952	965	953	959	967	973	977	983	986	992	997	1,003	1,010	1,015	1,021	1,027	1,036	1,042	1,050
REQUIRED RESOURCES	8,409	8,420	8,466	8,357	8,512	8,582	8,635	8,664	8,639	8,755	8,801	8,853	8,906	8,960	8,923	9,058	9,112	9,193	9,242	9,225
AVAILABLE RESOURCES	7,172	7,000	7,110	6,924	6,868	7,438	7,439	7,558	7,547	7,545	7,587	7,549	7,470	7,633	7,553	7,725	7,966	8,151	7,942	7,905
OPEN Position	1,237	1,420	1,356	1,433	1,644	1,144	1,196	1,106	1,092	1,210	1,214	1,304	1,436	1,327	1,370	1,333	1,146	1,042	1,300	1,320
Company	(All)																			
Row Labels	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
existing																				
NVE.existing.Coal	**516**	**261**	**261**	**134**	**134**	**134**	**134**	-	-	-	-	-	-	-	-	-	-	-	-	-
NVE.existing.Gas	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,141**	**5,093**	**5,039**	**4,725**	**4,725**	**4,510**	**4,163**	**4,163**	**4,019**	**4,019**
NVE.existing.Renewable.PV	**5**	**5**	**5**	**4**	**4**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
NVE.existing.Renewable.WH	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**
PPA.existing.Conventional	**619**	**636**	**638**	**384**	**211**	**204**	**205**	**206**	**205**	**210**	**210**	**210**	**210**	**198**	**198**	**198**	**198**	**198**	**198**	**198**
PPA.existing.Renewable.BESS	-	-	**25**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**75**	**75**	**75**	**75**	**75**	**75**	-	-
PPA.existing.Renewable.CSP	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
PPA.existing.Renewable.GEO	**166**	**165**	**165**	**158**	**149**	**149**	**149**	**136**	**126**	**118**	**108**	**67**	**67**	**63**	**7**	**7**	**7**	**7**	**7**	-
PPA.existing.Renewable.HYDRO	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**5**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
PPA.existing.Renewable.LFG	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	-	-	-	-	-	-
PPA.existing.Renewable.PV	**203**	**270**	**353**	**481**	**481**	**382**	**382**	**382**	**382**	**382**	**382**	**378**	**378**	**378**	**378**	**378**	**374**	**374**	**354**	**294**
PPA.existing.Renewable.WIND																				
Spring Valley (12/2032)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	-	-	-	-	-	-
PPA.existing.Renewable.WIND Total	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	-	-	-	-	-	-
existing Total	**7,172**	**7,000**	**7,110**	**6,924**	**6,742**	**6,635**	**6,636**	**6,490**	**6,479**	**6,422**	**6,076**	**5,983**	**5,904**	**5,574**	**5,494**	**5,279**	**4,928**	**4,928**	**4,689**	**4,622**
placeholder																				
NVE.placeholder.Gas	-	-	-	-	-	-	-	-	-	-	**358**	**358**	**358**	**716**	**716**	**1,098**	**1,648**	**1,648**	**1,648**	**1,648**
PPA.placeholder.Gas	-	-	-	-	-	-	-	**265**	**265**	**265**	**265**	**265**	**265**	**400**	**400**	**400**	**400**	**400**	**400**	**400**
PPA.placeholder.renewable.GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**42**	**42**	**42**	**42**
PPA.placeholder.renewable.PV	-	-	-	-	-	-	-	-	-	**55**	**85**	**140**	**140**	**140**	**140**	**145**	**145**	**330**	**360**	**390**
placeholder Total	-	-	-	-	-	-	-	**265**	**265**	**320**	**708**	**763**	**763**	**1,256**	**1,256**	**1,643**	**2,235**	**2,420**	**2,450**	**2,480**
proposed																				
PPA.proposed.Renewable.BESS	-	-	-	-	**76**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**
PPA.proposed.Renewable.PV	-	-	-	-	**50**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**
proposed Total	-	-	-	-	**126**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**

H. Environmental Externalities And Net Economic Benefits

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

1. Overview Of Relevant Regulations

The regulations require the Companies to rank its power supply options on the basis of the PWRR and the Present Worth of Societal Costs ("PWSC"). The PWSC of a resource case is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility…."[30] 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."[31] In addition, the August 2018 Order of the Commission in Docket No. 17-07020 requires that environmental costs include estimates of the "social cost of carbon" and proscribes 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 and, if applicable, subsection 6 of that section."[32]

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

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

The Companies retained the services of NERA Economic Consulting ("NERA") to provide analyses of the environmental costs and net economic benefits for the five alternative resource cases.[33] Details on NERA's analyses of the five additional cases are provided in the NERA report (Technical Appendix Item ECON-6).

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[30] NAC § 704.937(4).
[31] NAC § 704.9359.
[32] NAC § 704.9359, as finalized on August 15, 2018 in connection with Senate Bill No. 65, chapter 383, Statutes of Nevada 2017, at page 2471.
[33] NERA is a global firm of experts who apply economic, finance, and quantitative principles to complex business and legal challenges. NERA has earned wide recognition for its work in energy, environmental economics and regulation, antitrust, public utilities regulation, transportation, health care, and international trade, among other areas of expertise. References to NERA in this document relate to the authors of the NERA report; the analyses and conclusions in the NERA report represent those of the authors and do not necessarily represent those of NERA or any of its clients.

2. Carbon Dioxide Price Scenarios

a. BACKGROUND

On October 23, 2015, the U.S. Environmental Protection Agency ("EPA") published the Final Clean Power Plan ("CPP") rule to regulate carbon dioxide ("CO_2") emissions from existing fossil fuel-fired power plants under Section 111(d) of the Clean Air Act. In response to litigation challenging EPA's promulgation of the CPP, on February 9, 2016, the Supreme Court "stayed" the CPP. On March 28, 2017, President Donald Trump signed the Executive Order on Energy Independence (E.O. 13783), which disbanded the Interagency Working Group on Social Costs of Greenhouse Gases ("Interagency Working Group") and called for a review of the CPP. On October 16, 2017, EPA formally proposed to repeal the CPP after completing its initial review.[34] On August 21, 2018, EPA proposed a new rule to replace the CPP entitled the Affordable Clean Energy (ACE) Rule.[35]

At this point, it seems very certain that the CPP will not go into effect in 2022 as set out in the schedule outlined in the Final CPP. Indeed, neither the CPP nor a similar policy is likely to be implemented during the Trump Administration, which will extend at least until the beginning of 2021.

To account for the possibility of national regulation of utility greenhouse gas emissions in the future, however, it also seems appropriate to consider a scenario that includes a national cap-and-trade program similar in structure to programs that have been considered by the U.S. Congress and evaluated in prior IRPs. In June 2009, the U.S. House of Representatives passed an economy-wide cap-and-trade program for greenhouse gas ("GHG") emissions, commonly referred to as the "Waxman-Markey Bill" (U.S. House of Representatives 2009), which set goals of reducing GHG emissions by 17 percent below 2005 levels by 2020 and 83 percent below 2005 levels by 2050. Senators John Kerry and Joe Lieberman proposed a similar bill in the U.S. Senate in 2010, but it did not proceed to a vote in the full Senate. The cap-and-trade approach has various well-recognized advantages over a regulatory approach, including more complete incentives to minimize the overall national cost of achieving emission reductions. In addition, compared to a carbon tax, the cap-and-trade approach provides more convenient opportunities to mitigate transition and distributional impacts of carbon policy.

b. CARBON PRICE TRAJECTORY USED IN THESE ANALYSES

Clearly there is considerable uncertainty regarding the potential future national regulation of CO_2 emissions from existing power plants and the extent to which regulations might impose a "price" on CO_2 emissions. To account for a range of future CO_2 policies, NERA developed several alternative CO_2 scenarios, one of which would involve no federal regulation ("No Carbon Price" scenario) and three of which would involve establishing national cap-and-trade programs of varying stringency.

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[34] See EPA 40 CFR Part 60, p. 48036 https://www.gpo.gov/fdsys/pkg/FR-2017-10-16/pdf/2017-22349.pdf
[35] See EPA 40 CFR Part 60, p. 44748 https://www.govinfo.gov/content/pkg/FR-2018-08-31/pdf/2018-18755.pdf

NERA developed the full set of results for a "Mid CO_2 Price" scenario, in which a national cap-and-trade program is assumed to be put in place, with a cap consistent with allowance prices assumed to begin in 2025 at $10 per metric ton (2017$) and increase each year at a 5 percent real rate. NERA also developed some information for a "Low CO_2 Price" scenario and a "High CO_2 price" scenario, in which the CO_2 price is assumed to begin in 2025 at $5 per metric ton (2017$) and $20 per metric ton (2017$), respectively, and increase each year at the same real interest rate.

NERA also developed estimates of the effects of the Mid CO_2 Price scenario on fuel prices (natural gas and coal). NV Energy used these effects on fuel prices, as well as the CO_2 prices, in its modeling of the five additional cases. These differences in CO_2 and fuel prices lead to differences in the generation of various units under the five cases.[36]

3. Load Forecast Scenarios Modeled

NERA developed analyses for the two demand (load) forecasts developed by NV Energy for this additional IRP submission.

1. *"Base" load forecast*. This demand forecast represents NV Energy's baseline load forecast based on current information on its customers.

2. *"All Eligible" load forecast*. This energy demand forecast reflects NV Energy's load projection under the assumption that all "eligible customers" (as defined in NRS 704B) elect to purchase electricity directly from a provider other than NV Energy.

Section D of the NERA report provides NV Energy's demand projections under these two load forecasts.

4. Environmental Costs For Conventional And Toxic Air Emissions

NERA uses a damage value approach to develop estimates of the environmental costs in Nevada of conventional and toxic air emissions. This approach begins with the premise that the conceptually correct measure of the value of pollutant emissions is equal to the value of the damages caused by those emissions (assuming no binding cap-and-trade program or other price for emissions). Damages can include effects on health, visibility, and agriculture.[37] 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 verified this information).

Figure NERA–1 presents the estimated environmental costs of conventional and toxic air emissions for the five additional cases. The table 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

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[36] The carbon price scenarios and fuel price impacts were developed by NERA for submission in Docket No. 19-06003 and were not updated for this docket. As discussed in the NERA report, NERA does not believe changes in energy market and other projections over the last year affect the applicability of the 2018 analysis to evaluation of the additional five cases.

[37] 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.

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 necessary site-specific data were unavailable; however, CO emissions projections are included in the NERA report. As noted in the NERA report, the national SO_2 cap is not expected to be binding and thus costs from SO_2 emissions are evaluated based on damage values like other air emissions (rather than modeled as covered by a cap-and-trade program as in some past IRPs). Based on their inclusion in the MATS regulation, emissions of mercury and hydrogen chloride (“HCl”) are also included. The MATS regulation uses particulate matter (“PM”) emissions as a proxy for non-mercury metallic air toxics, but this element of the MATS regulation does not lead to additional environmental costs because PM emissions are already included based upon the NAAQS. HCl is not monetized because EPA does not provide the relevant information in the MATS regulatory impact analysis; however, HCl emission projections are included in the NERA report.

FIGURE NERA–1. PRESENT VALUES OF ENVIRONMENTAL COSTS FOR CONVENTIONAL AIR EMISSIONS AND TOXICS (2019$ MILLIONS)

	MSA	All Placeholder	Moapa	SBS	Arevia
NOx					
Base	$9.24	$9.33	$9.31	$9.29	$9.25
All Eligible	$7.17	$7.11	$7.06	$7.06	$7.07
PM					
Base	$149.51	$155.32	$154.11	$153.89	$151.51
All Eligible	$124.85	$132.18	$129.47	$128.99	$127.50
VOC					
Base	$0.00	$0.00	$0.00	$0.00	$0.00
All Eligible	$0.00	$0.00	$0.00	$0.00	$0.00
CO					
Base	-	-	-	-	-
All Eligible	-	-	-	-	-
SO2					
Base	$20.22	$19.88	$19.76	$19.65	$19.89
All Eligible	$16.52	$14.40	$14.46	$14.54	$15.38
Mercury					
Base	$0.00	$0.00	$0.00	$0.00	$0.00
All Eligible	$0.00	$0.00	$0.00	$0.00	$0.00
HCl					
Base	-	-	-	-	-
All Eligible	-	-	-	-	-
Total					
Base	$178.97	$184.53	$183.18	$182.82	$180.64
All Eligible	$148.55	$153.69	$150.98	$150.59	$149.96

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by the Companies.

Total may differ from the sum of the rows due to independent rounding.

"-" denotes that the environmental costs of the air emission are not monetized.

Figure NERA-2 shows the differences in environmental costs for conventional air emissions and air toxics for four of the cases relative to the preferred case (MSA case). These results show that for both load forecasts, the MSA case has the smallest conventional and toxic air emissions environmental costs and that the All Placeholder case has the largest costs.

FIGURE NERA-2. PRESENT VALUES OF THE DIFFERENCES IN ENVIRONMENTAL COSTS OF CONVENTIONAL AIR EMISSIONS AND TOXICS, RELATIVE TO THE MSA CASE, 2019-2048 (2019$ MILLIONS)

	MSA	All Placeholder	Moapa	SBS	Arevia
Base	-	$5.56	$4.21	$3.85	$1.67
All Eligible	-	$5.14	$2.43	$2.04	$1.41

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by NV Energy.

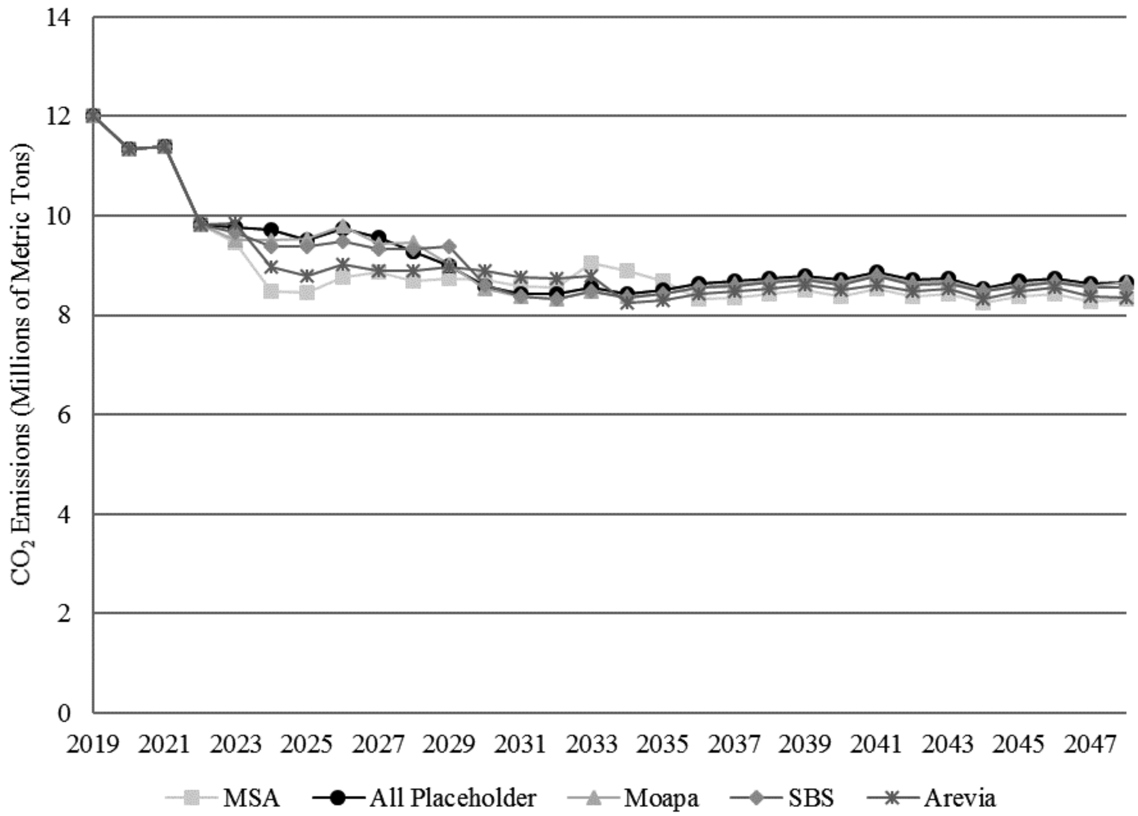
5. Social Cost Of Carbon For Carbon Dioxide Emissions

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

Estimates of Carbon Dioxide Emissions

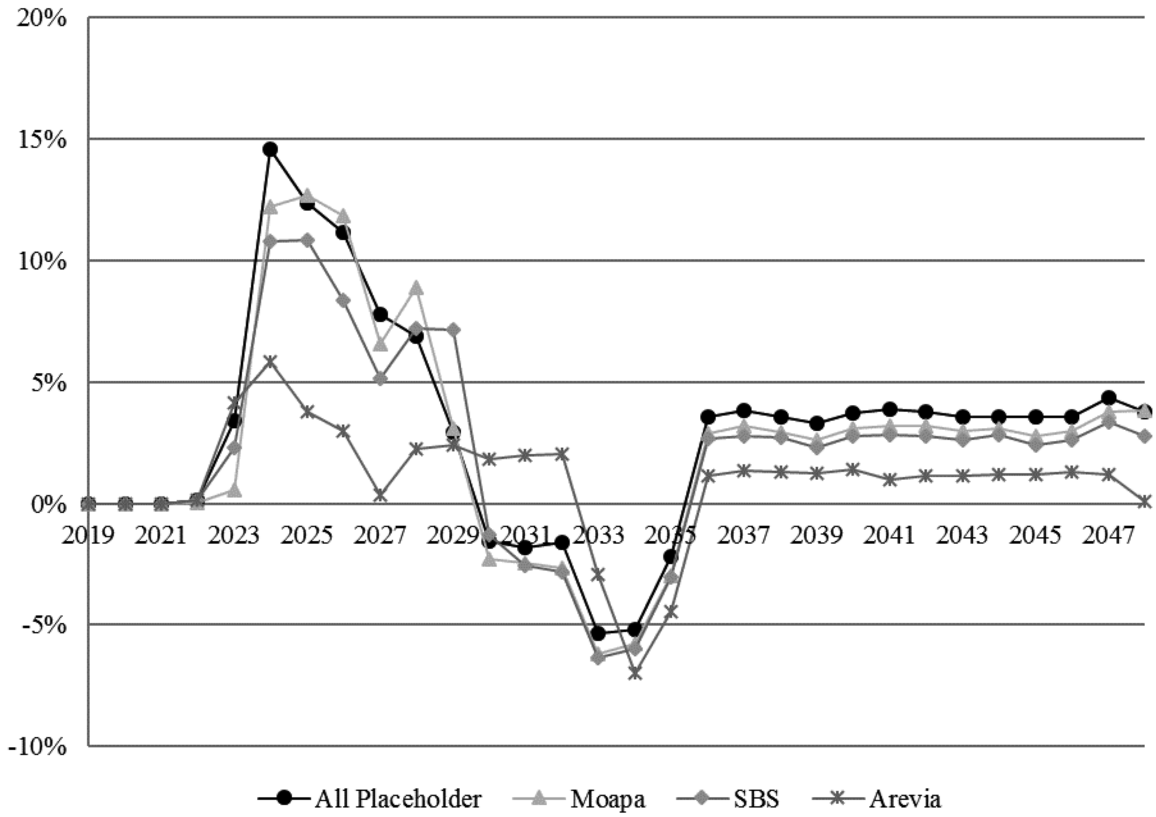
NERA developed estimates of carbon dioxide emissions over time for the five additional cases using information from modeling done by NV Energy and from other sources. Figure NERA-3 provides these estimates under the Base load forecast for each of the resource cases, with Figure NERA-4 showing estimates for the other four cases relative to those for the preferred case (MSA case). Figure NERA-5 provides these estimates under the All Eligible load forecast for each of the resource cases, with Figure NERA-6 showing estimates for the other four cases relative to those for the preferred case (MSA case).

FIGURE NERA-3. CARBON DIOXIDE EMISSIONS UNDER THE BASE LOAD FORECAST, 2019-2048 (2019$ MILLIONS)



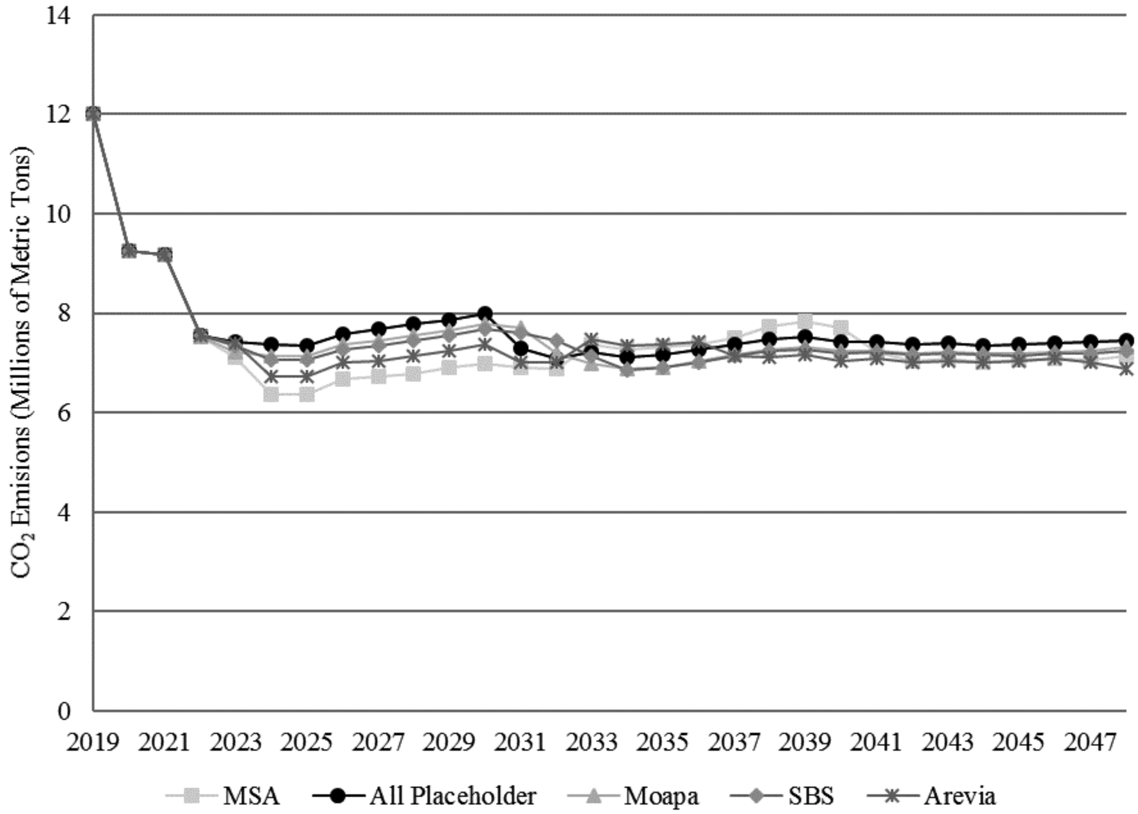
Notes: All values are under the Base load forecast scenario.

FIGURE NERA-4. PERCENTAGE DIFFERENCE IN CARBON DIOXIDE EMISSIONS UNDER THE BASE LOAD FORECAST, RELATIVE TO THE MSA CASE, 2019-2048 (2019$ MILLIONS)



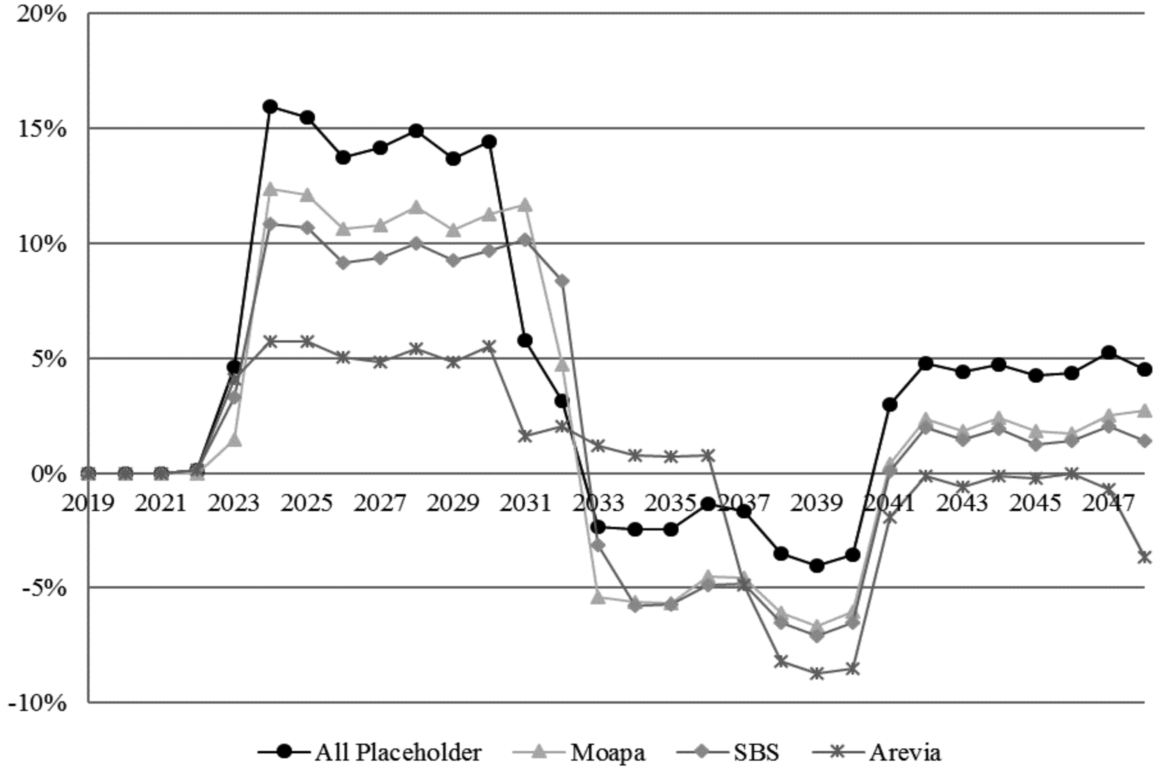
Notes: All values are percentage differences relative to the emissions for the MSA case under the Base load forecast scenario.

FIGURE NERA-5. CARBON DIOXIDE EMISSIONS UNDER THE ALL ELIGIBLE LOAD FORECAST, 2019-2048 (2019$ MILLIONS)



Notes: All values are under the All Eligible load forecast scenario.

FIGURE NERA-6. PERCENTAGE DIFFERENCE IN CARBON DIOXIDE EMISSIONS UNDER THE ALL ELIGIBLE LOAD FORECAST, RELATIVE TO THE MSA CASE, 2019-2048 (2019$ MILLIONS)



Notes: All values are percentage differences relative to the emissions for the MSA case under the All Eligible load forecast scenario.

Methodology Required by the Commission to Value Carbon Dioxide Emissions

Subsection 5 of the August 2018 Commission Order requires that "the social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the 'Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis' released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016."[38]

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

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

NERA used its estimates of future allowance prices under the Mid CO_2 Price scenario as measures of the costs of CO_2 emissions that are internalized as private costs to the utility; this approach is consistent with NV Energy's use of these prices in the PROMOD modeling. In compliance with the August 2018 Commission Order, NERA calculated the social cost of carbon as the Interagency Working Group August 2016 values minus the allowance prices.

Social Costs of Carbon

Figure NERA-7 shows the ranges of CO_2 costs (as present values) for the five resource cases using the four sets of future global economic costs and the projected Mid CO_2 allowance prices. The lowest values reflect a 5 percent discount rate (and the average of the damages distribution), while the highest values reflect a 3 percent discount rate and the 95th percentile of the damages distribution. Figure NERA-8 shows differences in the social costs of carbon for the other four cases relative to the MSA case (the Preferred Plan). Under both load forecasts, the MSA case has the lowest social costs of carbon and the All Placeholder case has the highest social cost of carbon.

FIGURE NERA-7. PRESENT VALUES OF SOCIAL COSTS OF CARBON, 2019-2048 (2019$ MILLIONS)

	MSA			All Place			Moapa			SBS			Arevia		
Base	$1,403	to	$33,751	$1,441	to	$34,712	$1,434	to	$34,545	$1,432	to	$34,454	$1,420	to	$34,066
All Elligible	$1,154	to	$27,978	$1,198	to	$29,105	$1,183	to	$28,573	$1,181	to	$28,492	$1,169	to	$28,099

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 based on values reported by Interagency Working Group (2016) and the allowance price projections for the Mid CO_2 Price scenario. Minimum values reflect a 5 percent discount rate and the average of the damages distribution, while maximum values reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

FIGURE NERA-8. DIFFERENCES IN PRESENT VALUES OF SOCIAL COSTS OF CARBON, RELATIVE TO THE MSA CASE, 2019-2048 (2019$ MILLIONS)

	MSA	All Place	Moapa	SBS	Arevia
Base	-	\$38 to \$961	\$30 to \$793	\$28 to \$703	\$16 to \$315
All Eligible	-	\$45 to \$1,127	\$29 to \$595	\$28 to \$513	\$15 to \$120

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 based on values reported by Interagency Working Group (2016) and the allowance price projections for the Mid CO_2 Price scenario. Minimum values reflect a 5 percent discount rate and the average of the damages distribution, while maximum values reflect a 3 percent discount rate and the 95th percentile of the damages distribution. Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text

NERA has in prior IRP's noted that the global values developed by the Interagency Working Group are not comparable to the environmental costs calculated for air and toxic emissions for several reasons: (a) the Interagency Working Group values are more uncertain partly because they are based upon impacts in the distant future; (b) the Interagency Working Group values are based on different discount rates than the private (NV Energy) discount rates used to calculate the present value of the other environmental costs; and (c) the Interagency Working Group values are based upon global damages rather than U.S. or Nevada-specific damages.

6. Other Environmental Effects

Water Quality, Solid Waste and Land Use

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

Additional Costs of Water Consumption

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

Figure NERA-9 shows the estimated additional costs of water consumption (*i.e.*, the added costs beyond those already included in the PWRR) for the five resource cases.

FIGURE NERA-9. PRESENT VALUE OF ADDITIONAL WATER COST, 2019-2048

	MSA	All Placeholder	Moapa	SBS	Arevia
Base	$11.6	$11.5	$11.5	$11.5	$12.0
All Eligible	$7.9	$8.7	$8.4	$8.4	$8.1

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by NV Energy.

Figure NERA–10 compares the present value of additional water costs relative to the MSA case. The differences in additional water costs reflect the differences over the five resource cases in the projected monthly generation for the plants owned by NV Energy that consume water from their own wells. The Arevia case is the only case to have greater additional water costs than MSA for both load forecasts. Note that all of the differences among cases are very small, less than $1 million.

FIGURE NERA–10. PRESENT VALUE OF DIFFERENCES IN ADDITIONAL WATER COSTS, RELATIVE TO THE MSA CASE, 2019-2048 (2019$ MILLIONS)

	MSA	All Placeholder	Moapa	SBS	Arevia
Base	-	-$0.1	-$0.2	-$0.2	$0.4
All Eligible	-	$0.8	$0.5	$0.5	$0.2

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by the Companies.

7. Present Worth Of Societal Cost

Figure NERA–11 and Figure NERA–12 provide information on the PWSC for the five resource cases under the Base load forecast. Figure NERA–13 and Figure NERA–14 provide information on the PWSC for the five resource cases under the All Eligible load forecast. As noted above, PWSC is defined as the sum of the PWRR and environmental costs. The figures also show the PWSC relative to the Preferred Plan (MSA case).

For both load forecasts, the MSA case has the lowest PWSC. Indeed, the MSA case has both the lowest environmental costs and lowest PWRR. In contrast, the All Placeholder case has the highest PWSC, with both the highest PWRR and the highest environmental costs.

FIGURE NERA–11. PRESENT WORTH OF SOCIETAL COSTS UNDER THE BASE LOAD FORECAST, 2019-2048 (2019$ MILLIONS)

	MSA	All Placeholder	Moapa	SBS	Arevia
PWRR	$24,380.1	$24,843.5	$24,748.9	$24,701.9	$24,556.7
Conventional Air Emission Costs	$179.0	$184.5	$183.2	$182.8	$180.6
Additional Water Costs	$11.6	$11.5	$11.5	$11.5	$12.0
Social Costs of Carbon	$1,403.3 to $33,751.1	$1,441.4 to $34,712.3	$1,433.6 to $34,544.5	$1,431.8 to $34,454.4	$1,419.8 to $34,
PWSC	$25,974.0 to $58,321.8	$26,481.0 to $59,751.8	$26,377.2 to $59,488.1	$26,327.9 to $59,350.6	$26,169.1 to $58,

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.

The SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

FIGURE NERA–12. PRESENT WORTH OF SOCIETAL COSTS UNDER THE BASE LOAD FORECAST, RELATIVE TO THE MSA CASE, 2019-2048 (2019$ MILLIONS)

	MSA	All Placeholder	Moapa	SBS	Arevia
PWRR	-	$463.4	$368.9	$321.8	$176.6
Conventional Air Emission Costs	-	$5.6	$4.2	$3.8	$1.7
Additional Water Costs	-	-$0.1	-$0.2	-$0.2	$0.4
Social Costs of Carbon	-	$38.1 to $961.1	$30.2 to $793.4	$28.4 to $703.3	$16.5 to $314.8
PWSC	-	$506.9 to $1,430.0	$403.1 to $1,166.3	$353.9 to $1,028.8	$195.1 to $493.4

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.

The SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

FIGURE NERA–13. PRESENT WORTH OF SOCIETAL COSTS UNDER THE ALL ELIGIBLE LOAD FORECAST, 2019-2048 (2019$ MILLIONS)

	MSA	All Placeholder	Moapa	SBS	Arevia
PWRR	$20,925.7	$21,281.2	$21,250.3	$21,203.8	$21,015.6
Conventional Air Emission Costs	$148.5	$153.7	$151.0	$150.6	$150.0
Additional Water Costs	$7.9	$8.7	$8.4	$8.4	$8.1
Social Costs of Carbon	$1,153.6 to $27,978.4	$1,198.3 to $29,105.1	$1,182.6 to $28,573.3	$1,181.1 to $28,491.7	$1,168.9 to $28,
PWSC	$22,235.7 to $49,060.5	$22,641.9 to $50,548.7	$22,592.3 to $49,983.0	$22,544.0 to $49,854.6	$22,342.6 to $49,

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.

The SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

FIGURE NERA–14. PRESENT WORTH OF SOCIETAL COSTS UNDER THE ALL ELIGIBLE LOAD FORECAST, RELATIVE TO THE MSA CASE, 2019-2048 (2019$ MILLIONS)

	MSA	All Placeholder	Moapa	SBS	Arevia
PWRR	-	$355.5	$324.6	$278.2	$89.9
Conventional Air Emission Costs	-	$5.1	$2.4	$2.0	$1.4
Additional Water Costs	-	$0.8	$0.5	$0.5	$0.2
Social Costs of Carbon	-	$44.8 to $1,126.8	$29.0 to $595.0	$27.6 to $513.3	$15.4 to $120.4
PWSC	-	$406.3 to $1,488.2	$356.6 to $922.5	$308.3 to $794.1	$106.9 to $211.9

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.

The SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

8. ECONOMIC IMPACTS

The NERA economic impact analysis uses the economic model developed by Regional Economic Models, Inc. ("REMI") to develop comprehensive estimates of economic impacts for the alternative resource cases, including the positive effects of expenditures in Nevada as well as the potential negative effects of greater electricity rates under more expensive cases. NV Energy provided NERA with information on electricity revenue forecasts under the five additional cases, which enabled NERA to estimate both the positive economic impacts of expenditures associated with the resource cases and the negative economic impacts of the electricity rate increases associated with these expenditures.

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, which allow one to estimate how changes in demand or supply in each relevant industry will affect all other industries. The I/O formulation also takes into account "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 direct "multiplier" effects in Nevada). REMI also provides estimates of the impacts on Nevada of higher electric rates when all the feedback mechanisms in the economy are taken into account (*e.g.*, changes in wages that result from changes in economic activity).

Simulations of the economy in REMI require a "baseline" scenario to which "alternative" scenarios can be compared. NERA assumed that the All Placeholder case under the Base load forecast scenario is the baseline or reference scenario, as this case involves the least change to the generation fleet and thus most closely approximates what resources might be implicit in REMI's reference scenario. The economic impact analysis is conducted over the period from 2019 to 2048, which is the period over which the Companies forecast electricity revenue. NERA developed economic impact assessments for the five primary cases under both the Base load forecast scenario and the All Eligible load forecast scenario. Although the All Placeholder case is assumed to be the baseline or reference scenario for purposes of the REMI modeling of expenditures, results were presented relative to the preferred case, the MSA case. These REMI results are presented under the Base load forecast scenario and the All Eligible load forecast scenario, as both expenditures and revenue requirements differ between the two load forecast scenarios.

Expenditures, Revenues and Economic Impacts Under the Base Load Forecast

Figure NERA–15 shows the average annual expenditures in Nevada under the Base load forecast. Only expenditures that occur in Nevada are included in these calculations because of the focus on estimating the economic impacts in Nevada. Note that these average annual values do not reflect differences over the 30-year period. As discussed in the NERA report, the expenditures exclude certain categories of expenditures, such as spot market purchases by the Companies, because those expenditures are assumed to flow to power producers outside Nevada (hence they would not generate positive economic impacts in Nevada). Given uncertainty related to the location of expenditures related to the Companies' open positions, the economic impact analysis assumes that 50 percent of open position expenditures would occur within the state and that 50 percent of open position expenditures would occur outside the state of Nevada.

FIGURE NERA–15. AVERAGE ANNUAL TOTAL EXPENDITURES UNDER THE BASE LOAD FORECAST, 2019-2048 (2019$ MILLIONS)

	All Placeholder	Moapa	SBS	Arevia	MSA
Construction	$679	$697	$692	$705	$738
Fuel	$668	$665	$663	$656	$650
O&M	$243	$245	$247	$253	$259
Total	**$1,589**	**$1,608**	**$1,602**	**$1,614**	**$1,647**

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–16 shows the differences in average annual expenditures over the period from 2019 to 2048 for each case relative to the REMI reference case (All Placeholder case under the Base load forecast scenario). These are the values that are included in the REMI modeling.

FIGURE NERA–16. AVERAGE ANNUAL TOTAL EXPENDITURES UNDER THE BASE LOAD FORECAST, RELATIVE TO THE ALL PLACEHOLDER CASE, 2019-2048 (2019$ MILLIONS)

	All Placeholder	Moapa	SBS	Arevia	MSA
Construction	-	$19	$13	$26	$60
Fuel	-	-$2	-$5	-$12	-$18
O&M	-	$2	$5	$11	$16
Total	-	**$19**	**$13**	**$25**	**$58**

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–17 shows the average annual values of the electricity revenue requirements for 2019-2048, apportioned by customer class, under the Base load forecast.

FIGURE NERA–17. AVERAGE ANNUAL ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS UNDER THE BASE LOAD FORECAST, 2019-2048 (2019$ MILLIONS)

	All Placeholder	Moapa	SBS	Arevia	MSA
Total	**$1,765**	**$1,757**	**$1,753**	**$1,736**	**$1,721**
Residential	$760	$757	$755	$747	$741
Commercial	$468	$466	$464	$461	$456
Industrial	$537	$534	$533	$529	$524

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–18 shows differences in average annual values of electricity revenue for each case relative to the All Placeholder case (the REMI baseline). These are the values that are used in the REMI analysis.

FIGURE NERA–18. ELECTRICITY REVENUE BY CUSTOMER CLASS UNDER THE BASE LOAD FORECAST, RELATIVE TO THE ALL PLACEHOLDER CASE, 2019-2048 (2019$ MILLIONS)

	All Placeholder	Moapa	SBS	Arevia	MSA
Total	**-**	**-$8**	**-$12**	**-$29**	**-$44**
Residential	-	-$3	-$5	-$14	-$19
Commercial	-	-$2	-$3	-$7	-$11
Industrial	-	-$3	-$4	-$8	-$13

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

REMI modeling takes as inputs the annual expenditures and electricity revenues relative to the REMI baseline (All Placeholder case) and develops economic impacts for the five additional cases over time. For each of the five resource cases, Figure NERA-19 shows REMI estimates of changes in future Nevada gross state product, personal income, state and local tax revenue and employment relative to values in 2018. REMI projects substantial economic growth in Nevada over this 30-year period under all of the five additional cases. In the case of employment, for example, Nevada is projected to increase employment by more than 175,000 jobs over the 30-year period from 2018 to 2048.

FIGURE NERA-19. ECONOMIC IMPACTS UNDER THE BASE LOAD FORECAST, 2019-2048

	Nevada Economic Impacts Compared to 2018						
	2019	2020	2021	2022	2023	2035	2048
MSA							
Gross State Product (millions of 2019 dollars)	5,307	9,054	11,859	15,264	21,257	56,637	105,672
Personal Income (millions of 2019 dollars)	6,134	11,731	16,415	21,156	26,246	69,049	124,705
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,137	2,651	6,974	12,595
Employment (total jobs)	29,869	36,288	34,373	36,908	62,992	51,390	179,648
All Placeholder							
Gross State Product (millions of 2019 dollars)	5,307	9,050	11,857	14,500	17,100	56,341	105,206
Personal Income (millions of 2019 dollars)	6,134	11,729	16,414	20,631	23,399	68,869	124,352
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,084	2,363	6,956	12,560
Employment (total jobs)	29,869	36,249	34,349	29,070	21,393	48,546	176,294
Moapa							
Gross State Product (millions of 2019 dollars)	5,307	9,051	11,857	15,260	17,147	56,452	105,577
Personal Income (millions of 2019 dollars)	6,134	11,729	16,414	21,153	23,425	68,952	124,607
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,136	2,366	6,964	12,585
Employment (total jobs)	29,869	36,250	34,350	36,865	21,782	49,471	179,046
SBS							
Gross State Product (millions of 2019 dollars)	5,307	9,052	11,858	14,502	18,303	56,412	105,280
Personal Income (millions of 2019 dollars)	6,134	11,730	16,414	20,632	24,228	68,933	124,411
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,084	2,447	6,962	12,566
Employment (total jobs)	29,869	36,268	34,361	29,091	33,493	49,126	176,805
Arevia							
Gross State Product (millions of 2019 dollars)	5,307	9,052	11,857	14,502	20,010	56,643	105,218
Personal Income (millions of 2019 dollars)	6,134	11,730	16,414	20,632	25,398	69,070	124,388
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,084	2,565	6,976	12,563
Employment (total jobs)	29,869	36,267	34,360	29,089	50,609	51,021	176,306

Note: The All Placeholder case (under the Base load forecast scenario) is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other four cases are in comparison to this case. Employment values include full time and part time jobs.

Source: REMI; NERA calculations as explained in text.

Figure NERA-20 provides estimates of growth for selected years in Nevada for the resource cases relative to the MSA case under the Base load forecast scenario. The results indicate that the MSA case shows the greatest economic impacts in most of these years for all four metrics (GSP, personal income, tax revenue, and employment). In 2035, however, GSP, personal income, and tax revenue would be slightly greater under the Arevia case than under the MSA case.

FIGURE NERA-20. ECONOMIC IMPACTS UNDER THE BASE LOAD FORECAST, RELATIVE TO THE MSA CASE, 2019-2048

	Nevada Economic Impacts Compared to 2018						
	2019	2020	2021	2022	2023	2035	2048
MSA							
Gross State Product (millions of 2019 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2019 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2019 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
All Placeholder							
Gross State Product (millions of 2019 dollars)	0	-4	-2	-764	-4,157	-296	-466
Personal Income (millions of 2019 dollars)	0	-2	-1	-525	-2,847	-180	-353
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-288	-18	-36
Employment (total jobs)	0	-39	-24	-7,838	-41,599	-2,844	-3,354
Moapa							
Gross State Product (millions of 2019 dollars)	0	-3	-2	-4	-4,110	-185	-95
Personal Income (millions of 2019 dollars)	0	-2	-1	-3	-2,821	-97	-98
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	0	-285	-10	-10
Employment (total jobs)	0	-38	-23	-43	-41,210	-1,919	-602
SBS							
Gross State Product (millions of 2019 dollars)	0	-2	-1	-762	-2,954	-225	-392
Personal Income (millions of 2019 dollars)	0	-1	-1	-524	-2,018	-116	-294
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-204	-12	-30
Employment (total jobs)	0	-20	-12	-7,817	-29,499	-2,264	-2,843
Arevia							
Gross State Product (millions of 2019 dollars)	0	-2	-2	-762	-1,247	6	-454
Personal Income (millions of 2019 dollars)	0	-1	-1	-524	-848	21	-317
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-86	2	-32
Employment (total jobs)	0	-21	-13	-7,819	-12,383	-369	-3,342

Note: The All Placeholder case (under the Base load forecast scenario) is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other four cases are in comparison to this plan. Employment values include full time and part time jobs.

Source: REMI; NERA calculations as explained in text.

Expenditures, Revenues and Economic Impacts Under the All Eligible Forecast

The following tables provide information on expenditures, revenue requirements and REMI economic impact results under the All Eligible load forecast. Expenditures and revenue requirements are lower for the All Eligible forecast than under the Base load forecast due to the lower projected electricity demand.

Figure NERA-21 presents average annual expenditures in Nevada under the All Eligible load forecast.

FIGURE NERA-21. AVERAGE ANNUAL TOTAL EXPENDITURES UNDER THE ALL ELIGIBLE LOAD FORECAST, 2019-2048 (2019$ MILLIONS)

	All Placeholder	Moapa	SBS	Arevia	MSA
Construction	$591	$642	$635	$648	$679
Fuel	$593	$580	$579	$568	$568
O&M	$211	$219	$221	$219	$229
Total	**$1,395**	**$1,442**	**$1,434**	**$1,435**	**$1,477**

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.

Figure NERA-22 shows the average annual relevant expenditures in each case relative to the All Placeholder case, the REMI baseline. These are the expenditure values that are used in the REMI modeling.

FIGURE NERA-22. AVERAGE ANNUAL TOTAL EXPENDITURES UNDER THE ALL ELIGIBLE LOAD FORECAST, RELATIVE TO ALL PLACEHOLDER CASE, 2019-2048 (2019$ MILLIONS)

	All Placeholder	Moapa	SBS	Arevia	MSA
Construction	-	$51	$44	$57	$88
Fuel	-	-$12	-$14	-$25	-$24
O&M	-	$8	$10	$8	$18
Total	**-**	**$47**	**$39**	**$40**	**$82**

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.

Figure NERA-23 shows the electricity revenue requirements by customer class under the All Eligible load forecast scenario.

FIGURE NERA-23. AVERAGE ANNUAL ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS UNDER THE ALL ELIGIBLE LOAD FORECAST, 2019-2048 (2019$ MILLIONS)

	All Placeholder	Moapa	SBS	Arevia	MSA
Total	**$1,513**	**$1,511**	**$1,507**	**$1,488**	**$1,477**
Residential	$662	$661	$659	$650	$645
Commercial	$396	$396	$395	$390	$387
Industrial	$455	$455	$454	$448	$445

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.

Figure NERA-24 compares the electricity revenue requirements in each case to those in the All Placeholder case, the REMI baseline. These are the values included in the REMI modeling.

FIGURE NERA-24. AVERAGE ANNUAL ELECTRICITY REVENUE BY CUSTOMER CLASS UNDER THE ALL ELIGIBLE LOAD FORECAST, RELATIVE TO THE ALL PLACEHOLDER CASE, 2019-2048 (2019$ MILLIONS)

	All Placeholder	Moapa	SBS	Arevia	MSA
Total	**-**	**-$2**	**-$6**	**-$26**	**-$36**
Residential	-	-$1	-$3	-$12	-$17
Commercial	-	$0	-$1	-$6	-$9
Industrial	-	$0	-$2	-$7	-$10

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.

Figure NERA-25 presents the REMI results, showing growth in the Nevada economy for the five resource cases from 2018 levels under the All Eligible load forecast scenario.

FIGURE NERA-25. ECONOMIC IMPACTS UNDER THE ALL ELIGIBLE LOAD FORECAST, 2019-2048

	Nevada Economic Impacts Compared to 2018						
	2019	2020	2021	2022	2023	2035	2048
MSA							
Gross State Product (millions of 2019 dollars)	5,308	9,040	11,845	15,257	21,256	56,469	105,626
Personal Income (millions of 2019 dollars)	6,134	11,763	16,450	21,200	26,295	68,969	124,722
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,141	2,656	6,966	12,597
Employment (total jobs)	29,871	36,106	34,151	36,734	62,832	49,350	178,233
All Placeholder							
Gross State Product (millions of 2019 dollars)	5,308	9,036	11,843	14,493	17,082	56,570	105,321
Personal Income (millions of 2019 dollars)	6,134	11,761	16,448	20,675	23,436	69,088	124,456
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,088	2,367	6,978	12,570
Employment (total jobs)	29,871	36,067	34,127	28,892	21,043	49,937	176,089
Moapa							
Gross State Product (millions of 2019 dollars)	5,308	9,037	11,843	15,254	17,129	56,697	105,804
Personal Income (millions of 2019 dollars)	6,134	11,761	16,448	21,198	23,461	69,206	124,800
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,141	2,370	6,990	12,605
Employment (total jobs)	29,871	36,068	34,129	36,692	21,432	50,906	179,702
SBS							
Gross State Product (millions of 2019 dollars)	5,308	9,038	11,844	14,495	18,286	56,679	105,432
Personal Income (millions of 2019 dollars)	6,134	11,762	16,449	20,676	24,266	69,147	124,548
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,088	2,451	6,984	12,579
Employment (total jobs)	29,871	36,086	34,139	28,913	33,151	50,743	176,898
Arevia							
Gross State Product (millions of 2019 dollars)	5,308	9,038	11,844	14,495	20,010	56,451	105,302
Personal Income (millions of 2019 dollars)	6,134	11,762	16,449	20,676	25,452	68,965	124,477
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,088	2,571	6,965	12,572
Employment (total jobs)	29,871	36,085	34,138	28,911	50,477	49,149	175,852

Note: The All Placeholder case (under the Base load forecast scenario) is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other four cases are in comparison to this plan. Employment values include full time and part time jobs.

Source: REMI; NERA calculations as explained in text.

Figure NERA-26 shows REMI results under the All Eligible load forecast scenario for each case, relative to the MSA case. The results indicate that the MSA case shows the greatest economic growth for all four metrics (GSP, personal income, tax revenue, and employment) under the All Eligible load forecast in the years up to 2023. In contrast, the All Placeholder, Moapa, and SBS cases have noticeably larger growth in all metrics in 2035, and the Moapa case continues to have greater growth in all metrics in 2048.

FIGURE NERA-26. ECONOMIC IMPACTS UNDER THE ALL ELIGIBLE LOAD FORECAST, RELATIVE TO THE MSA CASE, 2019-2048

	Nevada Economic Impacts Compared to 2018						
	2019	2020	2021	2022	2023	2035	2048
MSA							
Gross State Product (millions of 2019 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2019 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2019 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
All Placeholder							
Gross State Product (millions of 2019 dollars)	0	-4	-2	-764	-4,174	101	-305
Personal Income (millions of 2019 dollars)	0	-2	-2	-525	-2,859	119	-266
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-289	12	-27
Employment (total jobs)	0	-39	-24	-7,842	-41,789	587	-2,144
Moapa							
Gross State Product (millions of 2019 dollars)	0	-3	-2	-3	-4,127	228	178
Personal Income (millions of 2019 dollars)	0	-2	-2	-2	-2,834	237	78
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	0	-286	24	8
Employment (total jobs)	0	-38	-22	-42	-41,400	1,556	1,469
SBS							
Gross State Product (millions of 2019 dollars)	0	-2	-1	-762	-2,970	210	-194
Personal Income (millions of 2019 dollars)	0	-1	-1	-524	-2,029	178	-174
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-205	18	-18
Employment (total jobs)	0	-20	-12	-7,821	-29,681	1,393	-1,335
Arevia							
Gross State Product (millions of 2019 dollars)	0	-2	-1	-762	-1,246	-18	-324
Personal Income (millions of 2019 dollars)	0	-1	-1	-524	-843	-4	-245
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-85	0	-25
Employment (total jobs)	0	-21	-13	-7,823	-12,355	-201	-2,381

Note: The All Placeholder case (under the Base load forecast scenario) is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other four cases are in comparison to this plan. Employment values include full time and part time jobs.

Source: REMI; NERA calculations as explained in text.

APPLICATION EXHIBIT B

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

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

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

> **Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval of Third Amendment to the 2018 Joint Integrated Resource Plan, including a request for approval of three new renewable energy power purchase agreements, updates to the Transmission Action Plan including several new projects needed to allow the new renewable facilities to interconnect into the system, to meet distribution load growth, and to increase reliability.**

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

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

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

> **Nevada Power Company and Sierra Pacific Power Company are seeking approval of a third amendment to their 2018 Joint Integrated Resource Plan. The Companies are seeking to modify the approved Supply Side Action Plan to add three new renewable energy power purchase agreements to their portfolio. In addition, the Third Amendment includes modifications to the Transmission Plan to construct network upgrades to allow the new renewable energy projects to interconnect, develop a new substation and add breakers to a current substation increase reliability, which are driven by growth on the transmission and distribution systems, and some of which are necessary to interconnect new renewable energy.**

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

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

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

Not Applicable

[1] NRS 704.069 states in pertinent part:

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

APPLICATION EXHIBIT C

NV Energy
LOADS AND RESOURCES TABLE
Current_Moapa_SBS_Arevia

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Gross Peak	7,725	7,839	7,984	7,965	8,171	8,294	8,411	8,494	8,535	8,695	8,793	8,898	9,011	9,115	9,141	9,317	9,426	9,563	9,654	9,707	9,817	10,095	10,217	10,351	10,465	10,597	10,709	10,833	10,962	11,095
DSM	49	97	147	196	245	294	344	394	445	496	547	599	651	703	755	807	859	912	965	1,018	1,071	1,192	1,250	1,308	1,366	1,424	1,483	1,542	1,601	1,660
Private Generation	39	75	107	127	137	145	152	157	161	165	170	175	179	183	188	192	197	200	205	210	214	218	224	228	232	236	241	245	250	253
Avoided Capacity	177	199	229	239	236	241	253	257	272	265	267	268	278	280	291	281	285	293	284	305	306	298	295	312	308	323	315	318	314	327
Forecast System Peak	7,459	7,468	7,501	7,404	7,553	7,615	7,662	7,687	7,656	7,769	7,809	7,856	7,903	7,950	7,908	8,037	8,085	8,157	8,200	8,175	8,226	8,387	8,448	8,503	8,558	8,615	8,670	8,728	8,797	8,854
Sales Obligations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NET System Peak	7,459	7,468	7,501	7,404	7,553	7,615	7,662	7,687	7,656	7,769	7,809	7,856	7,903	7,950	7,908	8,037	8,085	8,157	8,200	8,175	8,226	8,387	8,448	8,503	8,558	8,615	8,670	8,728	8,797	8,854
Planning Reserves (13%)	950	952	965	953	959	967	973	977	983	986	992	997	1,003	1,010	1,015	1,021	1,027	1,036	1,042	1,050	1,056	1,063	1,070	1,077	1,084	1,091	1,098	1,106	1,114	1,122
REQUIRED RESOURCES	8,409	8,420	8,466	8,357	8,512	8,582	8,635	8,664	8,639	8,755	8,801	8,853	8,906	8,960	8,923	9,058	9,112	9,193	9,242	9,225	9,282	9,450	9,518	9,580	9,642	9,706	9,768	9,834	9,911	9,976
AVAILABLE RESOURCES	7,172	7,000	7,110	6,924	6,868	7,438	7,439	7,558	7,547	7,545	7,587	7,549	7,470	7,633	7,553	7,725	7,966	8,151	7,942	7,905	8,098	7,712	7,640	8,343	8,348	8,646	8,631	8,631	8,144	8,073
OPEN Position	1,237	1,420	1,356	1,433	1,644	1,144	1,196	1,106	1,092	1,210	1,214	1,304	1,436	1,327	1,370	1,333	1,146	1,042	1,300	1,320	1,184	1,738	1,878	1,237	1,294	1,060	1,137	1,203	1,767	1,903

Company (All)

Row Labels	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**
existing																														
NVE.existing.Coal																														
Valmy 2 (12/2025)	134	134	134	134	134	134	134	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Valmy 1 (12/2021)	127	127	127	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Navajo 1-3 (10/2019)	255	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NVE.existing.Coal Total	**516**	**261**	**261**	**134**	**134**	**134**	**134**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NVE.existing.Gas																														
Clark 10 (12/2034)	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark 11 - 22 (12/2038)	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	618	-	-	-	-	-	-	-	-	-	-
Clark 4 (12/2030)	54	54	54	54	54	54	54	54	54	54	54	54	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark 9 (12/2033)	215	215	215	215	215	215	215	215	215	215	215	215	215	215	215	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark Mt. 3 (12/2034)	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark Mt. 4 (12/2034)	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ft. Churchill 1 (12/2028)	113	113	113	113	113	113	113	113	113	113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ft. Churchill 2 (12/2028)	113	113	113	113	113	113	113	113	113	113	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Harry Allen 4 (12/2036)	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-
Harry Allen CC (12/2046)	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	-	-
Higgins CC (12/2039)	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530	-	-	-	-	-	-	-	-	-
Lenzie CC 1 (12/2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	-	-	-	-	-	-	-
Lenzie CC 2 (12/2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551	-	-	-	-	-	-	-
LV Gen 1 (12/2029)	48	48	48	48	48	48	48	48	48	48	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LV Gen 2 (12/2039)	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	-	-	-	-	-	-	-	-	-
Silverhawk CC (12/2039)	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	520	-	-	-	-	-	-	-	-	-
Sunpeak 3-5 (12/2031)	210	210	210	210	210	210	210	210	210	210	210	210	210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tracy 3 (12/2028)	108	108	108	108	108	108	108	108	108	108	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tracy 4&5 (12/2031)	104	104	104	104	104	104	104	104	104	104	104	104	104	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tracy CC (12/2043)	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	-	-	-	-	-
Harry Allen 3 (12/2036)	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-	-	-	-	-
NVE.existing.Gas Total	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,475**	**5,141**	**5,093**	**5,039**	**4,725**	**4,725**	**4,510**	**4,163**	**4,163**	**4,019**	**4,019**	**3,401**	**2,127**	**2,127**	**1,025**	**1,025**	**484**	**484**	**484**	-	-
NVE.existing.Renewable.PV	**5**	**5**	**5**	**4**	**4**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	-	-	-	-	-	-	-	-
NVE.existing.Renewable.WH	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	-	-	-	-	-	-	-	-
PPA.existing.Conventional	**619**	**636**	**638**	**384**	**211**	**204**	**205**	**206**	**205**	**210**	**210**	**210**	**210**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**	**198**
PPA.existing.Renewable.BESS																														
Dodge Flat BESS (12/2036)	-	-	-	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-
Battle Mtn BESS (12/2030)	-	-	25	25	25	25	25	25	25	25	25	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fish Spgs Ranch BESS (12/2036)	-	-	-	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-	-
PPA.existing.Renewable.BESS Total	-	-	**25**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**75**	**75**	**75**	**75**	**75**	**75**	-	-	-	-	-	-	-	-	-	-	-	-
PPA.existing.Renewable.CSP	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**150**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	-	-	-	-	-	-	-	-
PPA.existing.Renewable.GEO	**166**	**165**	**165**	**158**	**149**	**149**	**149**	**136**	**126**	**118**	**108**	**67**	**67**	**63**	**7**	**7**	**7**	**7**	**7**	-	-	-	-	-	-	-	-	-	-	-
PPA.existing.Renewable.HYDRO	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**5**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**	-	-	-	-	-	-	-	-	-	-
PPA.existing.Renewable.LFG	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PPA.existing.Renewable.PV	**203**	**270**	**353**	**481**	**481**	**382**	**382**	**382**	**382**	**382**	**382**	**378**	**378**	**378**	**378**	**378**	**374**	**374**	**354**	**294**	**288**	**284**	**280**	**280**	**280**	**260**	**220**	**190**	-	-
PPA.existing.Renewable.WIND																														
Spring Valley (12/2032)	15	15	15	15	15	15	15	15	15	15	15	15	15	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PPA.existing.Renewable.WIND Total	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	**15**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
existing Total	**7,172**	**7,000**	**7,110**	**6,924**	**6,742**	**6,635**	**6,636**	**6,490**	**6,479**	**6,422**	**6,076**	**5,983**	**5,904**	**5,574**	**5,494**	**5,279**	**4,928**	**4,928**	**4,689**	**4,622**	**3,995**	**2,717**	**2,605**	**1,503**	**1,503**	**942**	**902**	**872**	**198**	**198**
placeholder																														
NVE.placeholder.Gas																														
1-1x1 CC SN 382 MW_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	382	382	382	382	382	382	382	382	382
1-1x1 CC SN 382 MW_34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382
1-1x1 CC SN 382 MW_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	382	382	382	382	382	382	382	382	382	382	382	382	382	382
9-CT SN 90 MW_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	810	810	810	810	810	810	810	810	810	810
1-1x1 CC NN 358 MW_29	-	-	-	-	-	-	-	-	-	-	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358
2-CT NN 84 MW_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	168	168	168	168	168	168	168	168	168	168	168	168	168	168
1-2x1 CC NN 839 MW_44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	839	839	839	839	839
1-1x1 CC NN 358 MW_32	-	-	-	-	-	-	-	-	-	-	-	-	-	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358	358
1-2x1 CC SN 900 MW_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900	900	900	900	900	900	900	900
2-2x1 CC SN 900 MW_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,800	1,800	1,800	1,800	1,800	1,800	1,800
NVE.placeholder.Gas Total	-	-	-	-	-	-	-	-	-	-	**358**	**358**	**358**	**716**	**716**	**1,098**	**1,648**	**1,648**	**1,648**	**1,648**	**2,458**	**3,740**	**3,740**	**5,540**	**5,540**	**6,379**	**6,379**	**6,379**	**6,379**	**6,379**
PPA.placeholder.Gas																														
1-Summer Toll_265 MW_26	-	-	-	-	-	-	-	265	265	265	265	265	265	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1-Summer Toll_400 MW_32	-	-	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	-	-	-	-	-	-	-	-	-
PPA.placeholder.Gas Total	-	-	-	-	-	-	-	**265**	**265**	**265**	**265**	**265**	**265**	**400**	**400**	**400**	**400**	**400**	**400**	**400**	**400**	-	-	-	-	-	-	-	-	-
PPA.placeholder.renewable.GO																														
GO4N_47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42
GO4_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	42	42	42	42	42	42	42	42	42	42	42	42	42
PPA.placeholder.renewable.GO Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**42**	**84**	**84**
PPA.placeholder.renewable.PV																														
PV4_44	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20
PV2N_29	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

PV3N_38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15
PV4N_48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20
PV4_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20
PV1_43	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5
PV1_45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5
PV2_46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10
PV4_47A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4_47B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4_47C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4_47D	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV4_47E	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV3N_47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15
PV3_48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15
PV1N_37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5
PV1_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5
PV2_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10
PV4N_30A	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4N_30B	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV1_36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5
PV4_37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20
PV2_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10
PV4_47F	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
PV2_47	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
PV1N_34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PV4N_46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20
PV1_37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5
PV3_38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15
PV2_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10	10
PV4_36A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_36B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_36C	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_36D	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_36E	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_36F	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_36G	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_36H	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4_36I	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4N_28A	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV4N_28B	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV3N_28	-	-	-	-	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PV4N_29	-	-	-	-	-	-	-	-	-	-	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PV3N_30	-	-	-	-	-	-	-	-	-	-	-	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PV2N_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10
PV4N_45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20	20	20
PV2N_48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
PPA.placeholder.renewable.PV Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**55**	**85**	**140**	**140**	**140**	**140**	**145**	**145**	**330**	**360**	**390**	**400**	**410**	**450**	**455**	**460**	**480**	**505**	**535**	**680**	**725**
placeholder Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**265**	**265**	**320**	**708**	**763**	**763**	**1,256**	**1,256**	**1,643**	**2,235**	**2,420**	**2,450**	**2,480**	**3,300**	**4,192**	**4,232**	**6,037**	**6,042**	**6,901**	**6,926**	**6,956**	**7,143**	**7,188**
proposed																														
PPA.proposed.Renewable.BESS																														
1-Arevis_BESS_24	-	-	-	-	-	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354	354
1-Moapa_BESS@30_23	-	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	-
1-Moapa_BESS@70_23	-	-	-	-	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	-
1-SBS_BESS@60_24	-	-	-	-	-	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81	81
1-SBS_BESS@40_24	-	-	-	-	-	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
PPA.proposed.Renewable.BESS Total	**-**	**-**	**-**	**-**	**76**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**565**	**489**
PPA.proposed.Renewable.PV																														
1-Arevia_24	-	-	-	-	-	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138
1-Moapa_PV@30_23	-	-	-	-	15	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	-
1-Moapa_PV@70_23	-	-	-	-	35	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	-
1-SBS_PV@60_24	-	-	-	-	-	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
1-SBS_PV@40_24	-	-	-	-	-	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
PPA.proposed.Renewable.PV Total	**-**	**-**	**-**	**-**	**50**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**238**	**198**
proposed Total	**-**	**-**	**-**	**-**	**126**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**803**	**687**

JOHN P. MCGINLEY

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Third Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-06___

Prepared Direct Testimony of

John (Jack) P. McGinley

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

A. My name is John (Jack) P. McGinley. My current position is Vice President of Regulatory for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra", and together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6100 Neil Road in Reno, Nevada. I am filing testimony on behalf of the Companies.

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

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

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

A. Yes. I have testified before this Commission many times during my 35 years at the Company related to Integrated Resource Planning ("IRP"), Energy Supply Plan ("ESP"), General Rate cases ("GRC"), and various other Company filings. Most recently, I provided testimony in the 2019 Deferred Energy cases, and the Second Amendment to the 2018 Joint Integrated Resource Plan ("2018 Joint IRP") filing, Docket No. 19-05003.

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

A. The purpose of my testimony is to provide support for the Companies' Third Amendment to the 2018 Joint IRP. More specifically, I defend the Preferred Plan.

5. Q. ARE YOU SPONSORING ANY EXHIBITS OR APPENDICES?

A. Yes. I am sponsoring Section 1 of the Narrative attached to the Application, as well as Exhibit McGinley-Direct-1: Statement of Qualifications.

6. Q. WHAT IS THE SUBJECT MATTER OF THE THIRD AMENDMENT TO THE 2018 JOINT IRP?

A. The Third Amendment seeks approval of three new renewable purchase power agreements totaling 1,190 megawatt ("MW") with 590 MW of battery storage. The three renewable contracts are:

- Moapa Solar 200 MW (639,626 megawatt-hours ("MWh") with 75 MW battery storage, commercial operation date ("COD") of December 2022.

- Southern Bighorn Solar Farm 300 MW (1,014,929 MWh) with 135 MW battery storage, COD of September 2023.
- Gemini Solar 690 MW solar (2,226,581 MWh) with 380 MW battery storage, COD of December 2023.

The Third Amendment also requests approval of several transmission projects. First, the filing requests approval of transmission network upgrades associated with each of the three purchase power agreements listed above. Second the filing requests approval of a new 230-kilovolt ("kV") switchyard (which eventually will become a 230-kV substation) located within the Apex Industrial Park. Third, the filing requests approval to add a 230-kV break at the Machacek substation.

7. Q. PLEASE SUMMARIZE THE REASONS THE COMPANY SELECTED THE PREFERRED PLAN.

A. The Third Amendment to the 2018 Joint IRP addresses important trends in Nevada's changing energy landscape. While these trends are multi-faceted, they can be grouped into three categories: 1) the need to refocus resource planning on long-term objectives, rather than short-term outcomes; 2) delivering energy products that customers value (*i.e.*, products that customers desire because the products satisfy customers' needs); and (3) meeting Nevada's energy policies, including increases in the renewable portfolio standard targets and reducing carbon dioxide emissions.

- Refocusing on long-term objectives. In 2016 and 2017, Question 3 and customer direct access applications created significant uncertainty. Resource planning necessarily focused on the short-run. The defeat of Question 3 and energy supply decisions made by the Companies' largest commercial and industrial customers have reduced that uncertainty.

Accordingly, the Preferred Plan uses long-term obligations to reduce the Companies' open position. These solutions provide stability in both supply and pricing.

- Supports customer demands for energy supply. Customers are demanding lower prices, price stability, and renewable resources to meet their energy needs. The Third Amendment to the 2018 Joint IRP secures 1,190 MW of low-cost long-term renewable energy supply that provides price stability for customers
- The Third Amendment to the 2018 Joint IRP advances the energy policy goals of the state including those from the 80th Legislative Session. Senate Bill 358 doubles the renewable portfolio standard to 50 percent of retail sales by 2030, and Senate Bill 254 requires the State Department of Conservation and Natural Resources to inventory and report annually on greenhouse gas emissions for four industrial sectors including electricity production. SB 254 also requires the State to develop a statement of policies including, without limitation, regulations to achieve carbon reductions including a qualitative assessment of whether the policies support the long-term reduction of greenhouse gas emissions to zero by the year 2050. The renewable energy projects – with integrated battery storage – help position the Companies to achieve the Legislature's goal of making Nevada a leading producer and consumer of renewable, carbon-free energy.

In summary, the Preferred Plan adds new, renewable energy resources each with an integrated battery storage system to the Companies' portfolio of energy supply resources. Resource planning has become more complex. The Preferred Plan has many positive attributes. These positive attributes include, but are not limited to:

1. The lowest overall cost of the options analyzed by the Companies;

2. Reduced price volatility because each of the three new renewable purchase power agreements have fixed prices;

3. Full compliance with increased renewable portfolio standards;

4. The lowest amount of carbon emissions of all of the options analyzed by the Companies;

5. Less risk because the Companies' open capacity position is reduced with long-term commitments (instead of short-term purchases);

6. Coupling the three solar generation projects with an unprecedented, in Nevada's history, 590 MW of battery storage, which addresses the solar generation intermediacy problem and paves a pathway for sustainable reduction in fossil-fuel emissions;

7. A foundation for providing energy services and products necessary to meet the needs of large commercial and industrial customers; and,

8. It delivers economic, environmental, and health benefits to Nevadans, consistent with the policies established by the Nevada Legislature.

8. Q. HOW HAVE THE COMPANIES ORGANIZED THE THIRD AMENDMENT?

A. The Third Amendment includes a Narrative, Technical Appendices, and prepared Direct Testimony. The Narrative addresses each of the areas opened up by the Third Amendment: the load forecast, the addition of three new renewable purchase power contracts, and the transmission plan. The sponsors of each of the substantive portions of the Third Amendment are described below:

- **Terry Baxter**, **Manager of Load Forecasting**, sponsors the long-term load forecast addressed in Section 3 of the Narrative.

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

- **Dr. David Harrison, Jr., Economist and Senior Vice President at NERA Economic Consulting,** sponsors the discussion and analysis of environmental externalities contained in the Section 6 economic analysis discussion, as well as Technical Appendix Item ECON-9.
- **Mr. Shane Pritchard, Director Renewable Energy & Origination,** sponsors the Renewable Plan and the approval of three new renewable purchase power agreements totaling 1,190 MW of solar generation including 590 MW of battery storage addressed in Section 4 of the Narrative and Technical Appendices REN-1 through REN-9.
- **Mr. Marc Reyes, Treasurer,** sponsors the Supply-Side Plan addressing the economic analysis used to support approval of the three renewable purchase power agreements addressed in Section 6 of the Narrative, and Technical Appendix items ECON-1 through ECON-8.
- **Mr. Sachin Verma, Director Transmission System Planning**, sponsors the Transmission Plan additions to support a 230 kilovolt ("kV") switchyard to accommodate load growth in Apex Industrial Park in North Las Vegas as discussed in Section 5 of the Narrative, and Technical Appendix items TRAN-1 through TRAN-4.

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

A. Yes.

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

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

I graduated from the University of Nevada Reno in 1984 with a Bachelor of Science in Mechanical Engineering. Upon graduating from the University of Nevada, I have been employed full time by the Company for 35 years.

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

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

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

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

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF WASHOE)

I, JOHN P. MCGINLEY, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

____
JOHN P. MCGINLEY

Subscribed and sworn to before me
this 18th day of June, 2019.

LYNN D'INNOCENTI
Notary Public - State of Nevada
Appointment Recorded in Washoe County
No: 13-10786-2 - Expires May 2, 2021

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NOTARY PUBLIC

TERRY A. BAXTER

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Third Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-06___

Prepared Direct Testimony of

Terry A. Baxter

1. Q. WOULD YOU PLEASE STATE YOUR NAME, EMPLOYER, JOB TITLE, AND BUSINESS ADDRESS?

A. My name is Terry A. Baxter. I am the Manager of Load Forecasting for Sierra Pacific Power Company d/b/a/ NV Energy ("Sierra") and Nevada Power Company d/b/a NV Energy ("Nevada Power" and together with Sierra, the "Companies" or "NV Energy"). My business address is 6226 West Sahara Avenue, in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

2. Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER OF LOAD FORECASTING?

A. As the Manager of Load Forecasting, my primary responsibilities include forecasting sales volume, customer counts and peak demand for use in development of financial budgets, general rate cases, Energy Supply Plans ("ESP") and Integrated Resource Plans ("IRP").

3. Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE IN THE UTILITY INDUSTRY.

A. I hold a Master of Arts in Economics from the University of Arkansas located in Fayetteville, Arkansas, and a Bachelor of Science in Economics from the University of Missouri at Rolla (now Missouri University of Science and Technology) located in Rolla, Missouri. I have been employed by the Companies since July 2007. Prior to my current position, I served as the Manager of Forecasting and Economic Analysis at Alliant Energy in Cedar Rapids, Iowa, for nine years, where I was responsible for load and revenue forecasting and load research. Prior to that, I was a Group Manager for seven years with Aspen Systems Corporation (now a division of Lockheed-Martin) overseeing analytical consulting projects for utilities and the U.S. government. I also have served as Manager of Load Research at Midwest Resources (now MidAmerican Energy Company) and as the Load Research Analyst at Missouri Public Service Company (now a part of Kansas City Power and Light Co., a division of Great Plains Energy). I have submitted reports and testimony regarding load forecasting and load research before the Iowa Utilities Board, the Wisconsin Public Service Commission, the Illinois Commerce Commission, the Minnesota Department of Commerce, the California Energy Commission, the California Public Utilities Commission and the Public Utilities Commission of Nevada ("Commission").

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE COMMISSION?

A. Yes, I have testified in numerous proceedings before the Commission including the Companies' 2018 Joint Integrated Resource Plan, Docket No. 18-06003.

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

A. No.

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

A. I have attached **Exhibit Baxter-Direct-1** which details my professional background and experience.

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

A. The purpose of my testimony is to support the NRS Chapter 704B all eligible forecast of native load described in the narrative ("All Eligible Forecast").

8. Q. ARE THE COMPANIES REQUESTING APPROVAL OF THE 704B ALL ELIGIBLE LOAD FORECAST?

A. No. The Companies are filing the All Eligible Forecast for informational purposes only.

9. Q. WHY ARE YOU FILING THE ALL ELIGIBLE FORECAST?

A. In Docket No. 18-06003, one intervenor noted the lack of assumptions in the load forecast related to customers' transition to distribution-only service after 2019. The Commission recognized in that order:

> While the Commission would find accurate NRS 704B load departure projections beyond 2019 valuable, the Commission realizes the inherent uncertainty that would accompany such projections and would have serious concerns about their accuracy. To provide such projections, NV Energy would not only have to accurately predict the magnitude and the timing of applications for departures but would also have to determine, with a degree of certainty, (1) whether the Commission would grant such applications; and (2) whether an applicant would still proceed with the exit following the Commission's decision imposing the departure conditions.[1]

The All Eligible Forecast is not an attempt to predict which customers will transition to distribution-only service or when such customers might file applications pursuant to Chapter 704B of the Nevada Revised Statutes. Instead, the All Eligible Forecast supplies the impact information on the load forecast, and on long-term planning, if all identified eligible customers were to begin purchasing distribution-only service (and stop purchasing energy) from the Companies.

10. Q. ARE YOU FILING WORKPAPERS WITH THIS ALL ELIGIBLE FORECAST?

A. Yes, the workpapers related to the All Eligible Forecast will be supplied to the Commission and parties.

[1] Page 10, Commission Order in Docket No. 18-06003 dated October 11, 2018.

11. Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATEMENT OF QUALIFICATIONS
OF
TERRY A. BAXTER

Education

Master of Arts	University of Arkansas, Fayetteville, AR, 1979, Economics
Bachelor of Science	University of Missouri-Rolla, Rolla, MO, 1976 Economics

Related Professional Experience

2007 to Present **Manager of Load Forecasting,** Nevada Power Company d/b/a NV Energy
My primary duties are the forecasting of customers, sales, peak demand, gas therms and gas design day therms, for use in supply planning, rate cases and budgeting. Additional responsibilities include production of forecast variance reports actual to budget, weather adjustment of peaks and sales, and participation in local population forecasting working groups. I have filed testimony and supporting documents and testified on numerous occasions before the Public Utility Commission of Nevada.

2003 to 2007 **Manager, Forecasting and Economic Analysis,** Alliant Energy
Responsible for the direction and technical work in the areas of statistical sample design and evaluation of load research samples, peak and energy forecasting, for both the gas and electric utilities, and associated regulatory filings, including Integrated Resource Plan filings in Iowa, Illinois, Minnesota and Wisconsin. In this position, I was also responsible for the monthly sales and revenue forecast and explanations of the monthly variance analysis, including actual to budget, year-over-year, and outlook for both operating companies: Wisconsin Power and Light Company and Iowa Power and Light Company. Also responsible for rate case sales and demand forecasts in Wisconsin and Minnesota. Filed direct testimony before the Minnesota Department of Commerce.

2001 to 2003 **Private Consultant**
Assisted utility companies in sample design and analysis of load research programs.

1998 to 2003 **Team Leader, Forecasting and Economic Analysis**, Alliant Energy
Responsible for the direction and technical work in the areas of statistical sample design and evaluation of load research samples, peak and energy forecasting, for both the gas and electric utilities, and associated regulatory filings for IES Utilities and Interstate Power Company and its successor company, Iowa Power and Light.

1991 to 1998 **Group Manager**, Aspen Systems Corporation
Responsible for the technical direction of utility consulting projects in the areas of sample design, DSM performance evaluation, market and survey research.

1985 to 1991 **Rate Engineer and Manager of Load Research, and Forecasting**, Iowa Power, Inc. /Midwest Energy
Responsible for all facets of the load research program, including sample design, analysis and equipment selection, as well as sales forecasting. Filed testimony before the Iowa Utilities Board.

1980 to 1995 **Load Research Analyst**, Missouri Public Service Company
Responsible for all facets of the load research program as well as class cost of service and marginal cost studies.

1979 to 1980 **Economic Analyst**, Illinois Commerce Commission
Responsible for examination of utility rate and regulatory filings.

Other

2007 to present	Steering Committee, EEI Load Forecasting Group
1998 to 2007	Member, AEIC Load Research Committee Marketing sub-committee chairman from 2001-2007.

Specialized Training

Econometric Modeling Using SAS/ETS Software, February, 1991.

SAS Macro Language, August 1990.

Forecasting Techniques using SAS/ETS Software, April, 1990.

Sampling Methods and Statistical Analysis in Power Systems Load Research, April, 1989.

A.E.I.C. Seminar in Advanced Sample Design and Analysis of Load Research Data, July 1987.

Itron Statistically Adjusted End Use (SAE) Training Workshop, November 2008.

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF WASHOE)

I, TERRY BAXTER, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

Terry A Baxter

TERRY BAXTER

Subscribed and sworn to before me

This 18th day of June, 2019.

LYNN D'INNOCENTI
Notary Public - State of Nevada
Appointment Recorded in Washoe County
No: 13-10786-2 - Expires May 2, 2021

Lynn DInnocenti

NOTARY PUBLIC

DAVID HARRISON, JR.

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Third Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-06___

Prepared Direct Testimony of

David Harrison, Jr.

I. INTRODUCTION

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

A. My name is David Harrison, Jr. I am an economist and Managing Director at NERA Economic Consulting ("NERA"), an international firm of economists. Established in 1961, NERA has earned wide recognition for its work in energy, environmental economics and regulation, antitrust, public utilities regulation, transportation, health care, and international trade. The work is performed by more than 500 professional staff members qualified in economics, statistics, mathematics, computer applications, and business administration. NERA operates in numerous offices across North America, Europe, Asia and Australia. My business address is 99 High Street, Boston, Massachusetts. I am filing testimony on behalf of Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra) (together the "Companies").

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

A. I received a Ph.D. in Economics from Harvard University, where I was a Graduate Prize Fellow. I also hold a B.A. magna cum laude in Economics from Harvard College, where I was a member of Phi Beta Kappa, and a M.Sc. in Economics from the London School of Economics, where I was the Rees Jeffreys Scholar.

Before joining NERA, I was an Associate Professor at the John F. Kennedy School of Government at Harvard University, where I taught microeconomics, energy and environmental policy, benefit-cost analysis, and other subjects. I was a member of the Faculty Steering Committee of the Energy and Environmental Policy Center at Harvard University, and a member of the Advisory Board of the Interdisciplinary Program in Health at the Harvard School of Public Health.

I earlier served as a Senior Staff Economist on the President's Council of Economic Advisors, where my areas of responsibility included energy and environment, natural resources, occupational health and safety, and transportation. I also have worked at the U.S. Department of Transportation, the U.S. Department of Housing and Urban Development, and the National Bureau of Economic Research. My full curriculum vita is provided in **Exhibit Harrison-Direct-1**.

3. Q. PLEASE SUMMARIZE YOUR BACKGROUND RELATED TO BENEFIT-COST ANALYSIS OF ENVIRONMENTAL POLICIES.

A. My background includes extensive experience related to benefit-cost analysis, particularly as it relates to environmental regulation. I have analyzed the benefits and costs of environmental policy for more than 40 years, beginning in 1974, when

I participated in the benefit-cost study of the automotive emission standards mandated by the 1970 Clean Air Act that was undertaken by the National Academy of Sciences under a Congressional directive. I have authored or co-authored two books and numerous articles and consulting reports related to the benefits and costs of environmental policies. At Harvard, the courses I taught in energy and environmental policy and microeconomics included analyses of major environmental policies, including those related to the Clean Air Act and other major environmental legislation. At the President's Council of Economic Advisors, I was an acting member of the Regulatory Council, the group charged with the responsibility of developing benefit-cost methodologies to evaluate federal regulatory requirements. As the principal staff member on the Regulatory Analysis Review Group, I participated in the review of major proposed regulations. These reviews included analyzing information prepared by federal agencies on the costs and benefits of proposed regulations, including those related to the Clean Air Act, the Clean Water Act, and other major environmental statutes.

At NERA, I have directed numerous projects related to benefit-cost assessments of environmental regulations, including air quality and climate change, water quality, and other categories. In the area of water quality, I have carried out fish protection analyses for numerous facilities on the East Coast, the Hudson River, the Great Lakes, and the West Coast. I have been a consultant to the South Coast Air Quality Management District, the Massachusetts Department of Environmental Protection, the U.S. Environmental Protection Agency ("U.S. EPA"), the Organization of Economic Cooperation and Development, the European Commission, the UK Department for Environment, Food and Rural Affairs, the Italian Ministry of the

Environment, and other public agencies, as well as to numerous private companies and organizations.

4. Q. PLEASE SUMMARIZE YOUR BACKGROUND RELATED TO CLIMATE CHANGE POLICY AND EMISSIONS TRADING PROGRAMS.

A. I have participated in the development and analysis of emissions trading programs for more than 30 years, beginning in 1979 when I was on the senior staff of the President's Council of Economic Advisors and the U.S. EPA was developing its emissions trading program to provide flexibility in meeting air quality objectives. In terms of cap-and-trade programs developed to address air quality concerns, I was a member of the advisory committee for the RECLAIM program, an innovative emissions trading program in the Los Angeles air basin developed in the early 1990's, and I advised on the Acid Rain Trading Program for electricity generators developed as part of the 1990 Clean Air Act Amendments. I have also participated in the development and analysis of the averaging, banking, and trading programs for mobile sources of air emissions.

With regard to climate change, I have participated actively in the development or evaluation of greenhouse gas ("GHG") emission trading programs and proposals throughout the globe, including in the United States (California, the Northeast, the Midwest, and various federal initiatives), Europe, Asia, and Australia. Along with NERA colleagues, I have advised the European Commission and the UK government on the development and implementation of the European Union Emissions Trading Scheme ("EU ETS"), the major GHG cap-and-trade program that has been implemented thus far. I have provided advice to government officials developing the Regional Greenhouse Gas Initiative ("RGGI") in the Northeast as well as the California cap-and-trade program and have evaluated proposed programs in various other jurisdictions. My colleagues and I have developed numerous evaluations of various federal legislative proposals to create a U.S. cap-and-trade program, as well as evaluations of other climate change policies.

5. Q. PLEASE SUMMARIZE YOUR EXPERIENCE RELATED TO ECONOMIC IMPACT ASSESSMENTS.

A. I have extensive experience evaluating the economic impacts of various governmental policies and projects, both public and private, including major energy facilities. In particular, I have led more than three dozen assessments of the economic impacts of energy and environment policies and various infrastructure programs. These assessments have involved a wide range of economic models and have considered numerous areas in the U.S. and abroad, including virtually all states in the United States (and assessments for the country as whole) as well as France, Spain, the European Union, the Bahamas, and countries in Africa and the Middle East.

6. Q. PLEASE SUMMARIZE YOUR SPECIFIC EXPERIENCE RELATED TO ASSESSING ENVIRONMENTAL COSTS AND ECONOMIC IMPACTS RELATED TO INTEGRATED RESOURCE PLANNING IN NEVADA.

A. In 1993, I directed two studies to evaluate the external costs of electric utility resource selection, one in southern Nevada and one in northern Nevada. These studies were prepared for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," the "Company," and together with Nevada Power the "Companies"). It is my understanding that the results from these studies were used by these Companies in previous resource plan filings that were approved by the Commission.

In most years since 2006, I have directed studies evaluating the environmental costs and economic benefits of the Integrated Resource Plans ("IRP") and related amendments for Nevada Power and Sierra. The Commission reviewed the 2006 study as well as my testimony on the subject as part of Nevada Power's 2006 IRP (Docket No. 06-06051) and Sierra's Thirteenth Amendment to its 2005-2024 IRP (Docket No. 06-07010). The Commission approved the Companies' requests in relevant part in April 2007. The Commission reviewed the 2007 study as well as my testimony on the subject as part of Sierra's 2007 IRP (Docket No. 07-06049) and Nevada Power's Fourth Amendment to its 2006 IRP (Docket No. 07-07013). The Commission approved the Companies' requests in relevant part in November 2007. The Commission reviewed the 2008 study as well as my testimony on the subject as part of Nevada Power's Eighth Amendment to its 2007-2026 IRP (Docket No. 08-05014) and Sierra's Third Amendment to its 2008-2027 IRP (Docket No. 08-05015). The Commission approved the Companies' requests in relevant part in October 2008. The Commission reviewed the 2009-2010 study as well as my testimony on the subject as part of Nevada Power's 2009 IRP (Docket No. 10-02009) and Sierra's Eighth Amendment to its 2008-2027 IRP (Docket No. 10-03023). The Commission approved the Companies' requests in relevant part in July 2010. The Commission reviewed the 2010 study as well as my testimony on the subject as part of Sierra's 2010 IRP (Docket No. 10-07003). The Commission approved the Companies' requests in relevant part in December 2010. The Commission reviewed two 2011 studies as well as my testimonies on the subject as part of Nevada Power's Second Amendment to its 2010-2029 IRP (Docket No. 11-

08011) and First Amendment to its 2009 IRP (Docket No. 11-03014). The Commission approved the Second Amendment to the 2010-2029 IRP in December 2011, and the First Amendment to the 2009 IRP in January 2012. I submitted the 2012 study as well as testimony on the subject on behalf of the Companies' 2013-2032 IRP in June 2012 (Docket No. 12-06053). In August 2012, I submitted a report and testimony on Sierra's Second Amendment to its 2010 IRP (Docket No. 12-08009). In July 2013, I submitted a report and testimony on Sierra's 2013 IRP (Docket No. 13-07005). In May 2014, I submitted a report and testimony on Nevada Power's Emissions Reduction and Capacity Replacement Plan (Docket No. 14-05003). In June 2015, I submitted a report and testimony on behalf of the Nevada Power's IRP (Docket No. 15-07004). In July 2016 I submitted a report and testimony on behalf of Sierra's 2016 IRP (Docket 16-07001). In August 2016, I submitted testimony on the second amendment to Nevada Power's 2015 IRP (Docket No. 16-08027). In September 2016 I submitted an additional report and testimony of behalf of Sierra's 2016 IRP in relation to the supplemental filing in response to Procedural Order 1 (Docket No. 16-07001). In June 2018 I submitted a report and testimony on behalf of the joint Nevada Power and Sierra 2018 IRP (Docket 18-06003).

II. TESTIMONY OBJECTIVES

7. Q. WHAT ARE THE PURPOSES OF YOUR TESTIMONY?

A. I have been asked by the Company to offer my expert opinion in five areas related to information on five additional resource cases being considered for the 2018 Integrated Resource Plan: (1) future national regulation of carbon dioxide ("CO_2") emissions from power plants, including the possibility of a "price" that would be placed on the Company's CO_2 emissions as well as the implications of CO_2 policies on the prices of fuels used by the Company; (2) external environmental costs for air emissions under the cases, including damage-based values for conventional and toxic emissions as well as estimates of the social cost of carbon for CO_2 emissions as required in the August 2018 Order of the Commission in Docket No. 17-07020 to implement Senate Bill 65; (3) evaluation of the external costs of other potential non-air environmental impacts; (4) external costs of the Company's water consumption that are not included in the PWRR for the cases; and (5) the economic benefits (i.e., economic impacts) to the Nevada economy under the cases. The results of my analyses are discussed in detail in a report I prepared in collaboration with NERA colleagues ("NERA Report"), which is provided in Technical Appendix Item ECON-[9].

8. Q. PLEASE PROVIDE AN OVERVIEW OF THE ALTERNATIVE CASES AND THE MAJOR ELEMENTS THAT DIFFERENTIATE THEM?

A. This third amendment to Nevada's 2018 Integrated Resource Plan considers the following five resource cases for meeting electricity demand and state renewable energy requirements from 2019 to 2048. These cases differ in the addition of different solar PV and battery storage power purchase agreements (PPA).

- "Moapa" case;
- "SBS" case;
- "Arevia" case;
- "MSA" case; and the
- "All Placeholder" case

DIFFERENCES IN POWER PURCHASE AGREEMENTS AMONG ADDITIONAL IRP CASES

The following are differences in renewable PPAs (including solar PV and battery energy storage) and related transmission among the five cases.

Moapa Case:

- Moapa Solar PV (200 MW) with battery energy storage (75 MW/ 375 MWh) by 2023.

SBS Case:

- Solar Bighorn Solar PV (300 MW) with battery energy storage (135 MW/ 540 MWh) by 2023.

Arevia Case:

- Arevia Solar PV (690 MW) with battery energy storage (380 MW/ 1416 MWh) by 2023.

MSA Case:

- Moapa; Solar PV (200 MW) with battery energy storage (75 MW/ 375 MWh) by 2023.
- Solar Bighorn Solar PV (300 MW) with battery energy storage (135 MW/ 540 MWh) by 2023.
- Arevia Solar PV (690 MW) with battery energy storage (380 MW/ 1416 MWh) by 2023.

All Placeholder Case:

- No additional solar PV or battery storage.

DIFFERENCES IN TRANSMISSION EXPENDITURES AMONG ADDITIONAL CASES.

The cases include various transmission network upgrades associated with integrating the new solar PV PPAs into the electric distribution system. Each of the additional PPAs would require additional expenditures by Nevada Power to upgrade networks.

These differences in solar and battery storage (and transmission) lead to differences in operation of various Company plants, purchases from other particular plants, and market purchases. Information on the common elements of the five cases is provided in the NERA Report.

The Company has selected the MSA case as the "Preferred Plan" and we calculate differences in results relative to this case.

III. LOAD FORECAST SCENARIOS

9. Q. PLEASE SUMMARIZE THE TWO LOAD FORECASTS USED IN YOUR ANALYSES.

A. NV Energy has provided results for the five additional cases under two load forecasts. The "Baseline" load forecast represents NV Energy's baseline load forecast based on the currently available information on their customers. The "All Eligible" load forecast reflects NV Energy's load projection under the assumption that all "eligible customers" (as defined in NRS 704B) elect to purchase electricity directly from a provider other than NV Energy. I present the results of the analyses under both of these load forecasts.

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IV. CARBON DIOXIDE PRICE SCENARIO

10. Q. PLEASE SUMMARIZE THE CARBON DIOXIDE PRICE SCENARIOS YOU HAVE DEVELOPED.

A. For my June 2018 submission for the 2018 initial IRP (Docket 18-06003), I developed several CO_2 price scenarios to reflect uncertainty regarding the potential future national regulation of CO_2 emissions from existing power plants and the extent to which regulations might impose a "price" on CO_2 emissions from power plants. One of the scenarios assumed no future national regulation, and thus no CO_2 price, and three of the scenarios assumed a national cap-and-trade program similar in structure to programs that have been considered by the U.S. Congress. The three national CO_2 cap-and-trade scenarios are assumed to begin in 2025, with prices that begin at $5 per metric ton ("low"), $10 per metric ton ("mid"), and $20 per metric ton ("high"). A cap-and-trade program has various well-recognized advantages over the regulatory approach, including greater incentives to minimize the overall U.S. cost of achieving carbon emission reductions. Moreover, relative to a carbon tax, a cap-and-trade program provides more straightforward mechanisms to deal with transitional costs as well as distributional concerns.

11. Q. WHICH CARBON DIOXIDE PRICE SCENARIO DID YOU USE FOR PURPOSES OF THIS SUBMISSION?

A. I used the "Mid CO2 Price" scenario for the analyses in this submission. Thus, all of the results developed here assume that a cap-and-trade program would begin in 2025 with allowance prices that start at $10 per metric ton and increase over time at a 5 percent real rate of increase. The June 2018 NERA Report provides additional information on this scenario.

12. Q. HOW DID YOU DEVELOP ESTIMATES OF THE EFFECTS OF THE CARBON DIOXIDE SCENARIOS ON THE PRICES THAT THE COMPANY WOULD PAY FOR FUELS?

A. I used the N$_{ew}$ERA model, a model developed and maintained by NERA that includes a detailed electric sector model and related integrated fuel price and macroeconomic models, as explained in the NERA Report. The electric sector model (the primary model used for my analysis) is a detailed model of the electric and coal sectors. Each of the more than 17,000 electric generating units in the United States is represented in the model. The model minimizes costs while meeting all specified constraints, such as demand, peak demand, emissions limits, and transmission limits. The model is similar to the National Energy Modeling System ("NEMS"), developed and maintained by the U.S. Energy Information Administration ("EIA") in the Department of Energy.

I used N$_{ew}$ERA to develop estimates of carbon dioxide prices and the impacts of these prices on fuel prices under the Mid CO_2 Price scenario. As requested by the Company, I estimated changes in prices for Henry Hub natural gas and Rocky Mountain coal (Utah and Colorado) and transmitted them to the Company for use in their PROMOD runs for the five additional cases.

13. Q. PLEASE EXPLAIN HOW THE CARBON DIOXIDE SCENARIOS AFFECT NEVADA POWER'S MODELING OF ITS ALTERNATIVE CASES.

A. The regulatory treatment of power plant CO_2 emissions and the associated fuel price changes have been incorporated into the Company's PROMOD runs for the Mid CO_2 Price scenarios. The prices of CO_2 emissions under the Mid CO_2 Price scenario are included in the costs to dispatch fossil-fuel generating units, and thus affect the generation of various units under the different cases. In turn, I use the Company's PROMOD projections along with other information to develop estimates of the environmental costs of various air emissions under the resource plans, including conventional and toxic pollutants as well as CO_2 emissions.

I also developed estimates of the value of free allowances that the Companies could receive under the potential cap-and-trade program modeled in the Mid CO_2 Price scenario in my June 2018 report. The value of these free allowances will reduce the net costs incurred by the Companies to comply with regulatory requirements. The net financial impact in a given year for the emissions from the Company's generation depends on the level of emissions, the price, and the number of emission allowances the Companies would receive for free under the program. I understand that the potential allowance allocation is incorporated into the Company's financial planning model.

14. Q. DO YOU EXPECT CHANGES IN PROJECTIONS OF FUTURE ENERGY MARKET CONDITIONS SINCE THE 2018 ANALYSIS WAS COMPLETED TO HAVE SUBSTANTIAL EFFECTS ON YOUR EVALUATIONS OF THE CARBON PRICE SCENARIO AND YOUR ANALYSES OF THE FIVE ADDITIONAL CASES?

A. No, I do not. The NERA report accompanying my testimony considers changes in energy market projections from those used in our June 2018 report to the latest Annual Energy Outlook ("AEO") prepared by the U.S. Energy Information Administration, the 2019 AEO. I conclude that these changes are not likely to have significant effects on the results. The NERA report also considers the implications of differences in forecasts of NV Energy electricity demand between the values used in the June 2018 report and the two updated load forecasts (Base and All Eligible) for the value of the initial allowances NV Energy could receive under the potential cap-and-trade program; the updated forecasts lead to relatively modest differences in the value of initial allowances (no more than 5.1 percent difference).

V. ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS

15. Q. PLEASE SUMMARIZE THE METHODS YOU USED TO ESTIMATE ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS.

A. I applied a "damage-function" framework to evaluate the environmental costs of air emissions for which sufficient data were available to estimate the potential damages related to health effects. The specific emissions in this category include nitrogen oxides ("NO_x"), volatile organic compounds ("VOC"), particulate matter ("PM"), mercury, and sulfur dioxide ("SO_2"). As discussed in the NERA Report, the national SO_2 cap set in the Acid Rain Trading Program is not binding—with allowance prices expected to be zero or close to zero—and thus SO_2 emissions are evaluated based on damage values rather than as covered by a binding cap-and-trade program as was appropriate in some earlier IRP analyses. The damage-function approach is a standard economic approach for assessing environmental costs when emissions are not capped. The damage values that I used for these emissions are primarily based on health effects associated with ambient PM (which depend on NO_x emissions that operate as precursors for PM as well as emitted PM) and ground-level ozone (which is formed by NO_x and VOC emissions), as described in the NERA Report. To develop this information, I relied on data and methodologies developed and used by the U.S. EPA as well as other information. I also estimated damage values for mercury from information developed by U.S. EPA in its assessments of the Mercury and Air Toxics Standards ("MATS"). As noted in the NERA Report, I did not assess the validity of the EPA information used in these calculations.

16. Q. PLEASE SUMMARIZE OTHER SOURCES OF INFORMATION YOU USED TO DEVELOP THE ENVIRONMENTAL COST ASSESSMENTS.

A. I relied on information provided by the Companies regarding the various resource plans. This information included emission rates for relevant facilities, forecasted annual generation and heat input for relevant facilities (based on the PROMOD dispatch modeling results), and other information as described in the NERA Report. The information provided by the Companies relates to both Nevada Power and Sierra, because the two systems were modeled jointly, and thus the joint plans involve emissions related to both the Nevada Power and Sierra systems. I supplemented the information from the Companies with relevant information from public sources; for example, as noted above, in estimating health and other effects and dollar values for various emissions, I relied on data and methodologies developed by U.S. EPA.

17. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE ENVIRONMENTAL COSTS OF AIR EMISSIONS.

A. Table 1 presents the estimated environmental costs related to air emissions other than carbon dioxide emissions under the two load scenarios. Table 2 summarizes the differences for the cases relative to the environmental costs of the MSA case. The tables include costs for emissions subject to the National Ambient Air Quality Standards ("NAAQS") and the recent MATS rule proposed by U.S. EPA. Based on

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the NAAQS, I have included emissions of NO_x, VOC, PM, carbon monoxide CO, and SO_2. Damage values for VOC emissions are zero because air quality modeling results indicate that, given ambient climatic conditions, changes in VOC emissions do not affect ozone concentrations in Nevada (which are driven at the margin by NO_x emissions). CO is not monetized because the requisite site-specific data were unavailable; however, CO emissions projections are provided in the NERA Report. Based on their inclusion in the MATS rule, emissions of mercury and HCl are also included. HCl is not monetized because U.S. EPA did not develop the relevant information in the MATS regulatory impact analysis; however, HCl emission projections are provided in the NERA Report. Note that the MATS rule uses PM emissions as a proxy for non-mercury metallic air toxics; however, since PM emissions are included based upon the NAAQS, this element of the MATS rule does not lead to estimates of additional environmental costs. The NERA report provides additional information on the methods used to develop environmental costs for these pollutants.

Table 1. Present Values of Environmental Costs for Conventional Air Emissions and Toxics, 2019-2048 (2019$ Millions)

	MSA	All Placeholder	Moapa	SBS	Arevia
NOx					
Base	$9.24	$9.33	$9.31	$9.29	$9.25
All Eligible	$7.17	$7.11	$7.06	$7.06	$7.07
PM					
Base	$149.51	$155.32	$154.11	$153.89	$151.51
All Eligible	$124.85	$132.18	$129.47	$128.99	$127.50
VOC					
Base	$0.00	$0.00	$0.00	$0.00	$0.00
All Eligible	$0.00	$0.00	$0.00	$0.00	$0.00
CO					
Base	-	-	-	-	-
All Eligible	-	-	-	-	-
SO2					
Base	$20.22	$19.88	$19.76	$19.65	$19.89
All Eligible	$16.52	$14.40	$14.46	$14.54	$15.38
Mercury					
Base	$0.00	$0.00	$0.00	$0.00	$0.00
All Eligible	$0.00	$0.00	$0.00	$0.00	$0.00
HCl					
Base	-	-	-	-	-
All Eligible	-	-	-	-	-
Total					
Base	$178.97	$184.53	$183.18	$182.82	$180.64
All Eligible	$148.55	$153.69	$150.98	$150.59	$149.96

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy.

Total may differ from the sum of the rows due to independent rounding.

"-" denotes that the environmental costs of the air emission are not monetized.

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Table 2. Present Values of the Differences in Environmental Costs of Conventional Air Emissions and Toxics, Relative to the MSA Case, 2019-2048 (2019$ Millions)

	MSA	All Placeholder	Moapa	SBS	Arevia
Base	-	$5.56	$4.21	$3.85	$1.67
All Eligible	-	$5.14	$2.43	$2.04	$1.41

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy.

In addition to the potential health costs associated with conventional air emissions and toxics, there are also potential non-health costs. As discussed in the report, we expect non-health damages to be small relative to the health damages and thus we would not expect their omission to have a major effect on the results, particularly the comparative results for the different cases.

18. Q. PLEASE COMMENT ON DIFFERENCES IN ENVIRONMENTAL COSTS RELATED TO CONVENTIONAL AND TOXIC AIR EMISSIONS UNDER THE VARIOUS RESOURCE CASES.

A. These results indicate that the MSA case has the smallest conventional and toxic air emissions costs and the All Placeholder case has the largest. The second largest costs are under the Moapa case, followed by the SBS and Arevia cases.

VI. SOCIAL COSTS OF CARBON FOR CARBON DIOXIDE EMISSIONS

19. Q. PLEASE DESCRIBE THE METHODOLOGY YOU USED TO DEVELOP ESTIMATES OF THE SOCIAL COST OF CARBON FOR CARBON DIOXIDE EMISSIONS.

A. The August 2018 Order of the Commission in Docket No. 17-7020 requires that environmental costs include estimates of the “social cost of carbon” and proscribes 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 NA [section] 704.937 and, if applicable, subsection 6 of that section." The analyses we developed complies with these regulatory requirements.

NERA developed estimates of carbon dioxide emissions over time under the various cases using information from modeling done by NV Energy and from other sources. The NERA report provides information on the trajectories of carbon dioxide emissions for each of the five additional cases and on the differences in emissions trajectories between the MSA case and the other four cases. These trajectories were developed for both of the load forecasts, the Base forecast and the All Eligible forecast.

Subsection 5 of the August 2018 Commission Order requires that "the social cost of carbon must be determined by subtracting the costs associated with emissions of carbon internalized as private costs to the utility pursuant to subsection 3 from the net present value of the future global economic costs resulting from the emission of each additional metric ton of carbon dioxide. The net present value of the future global economic costs resulting from the emission of an additional ton of carbon dioxide must be calculated using the best available science and economics such as the analysis set forth in the 'Technical Support Document: Technical Update of the

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Social Cost of Carbon for Regulatory Impact Analysis' released by the Interagency Working Group on Social Cost of Greenhouse Gases in August 2016."[1]

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

NERA used its estimates of future allowance prices under the Mid CO_2 Price scenario as measures of the costs of CO_2 emissions that are internalized as private costs to the utility; this approach is consistent with NV Energy's use of these prices in the PROMOD modeling. In compliance with the August 2018 Commission Order, NERA calculated the social cost of carbon as the Interagency Working Group August 2016 values minus the allowance prices.

[1] 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." As noted, the Commission in its August 2018 Order refers to the social cost of carbon as the difference between future global economic costs and the costs internalized as private costs (in this case the allowance prices). NERA adopts the terminology of the August 2018 Order in its current report (although its 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 August 2016 report (See Section III.B of NERA report)

20. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE SOCIAL COSTS OF CARBON DIOXIDE EMISSIONS FOR THE FIVE RESOURCE CASES.

A. Table 3 shows the ranges of CO_2 costs (as present values) for the five resource cases using the four sets of future global economic costs and the projected Mid CO_2 allowance prices. The lowest values reflect a 5 percent discount rate (and the average of the damages distribution), while the highest values reflect a 3 percent discount rate and the 95th percentile of the damages distribution. Table 4 shows differences in the social costs of carbon for the other four cases relative to the MSA case (the Preferred Plan).

Table 3. Present Values of Social Costs of Carbon, 2019-2048 (2019$ Millions)

	MSA			All Place			Moapa			SBS			Arevia		
Base	$1,403	to	$33,751	$1,441	to	$34,712	$1,434	to	$34,545	$1,432	to	$34,454	$1,420	to	$34,066
All Elligible	$1,154	to	$27,978	$1,198	to	$29,105	$1,183	to	$28,573	$1,181	to	$28,492	$1,169	to	$28,099

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 based on values reported by Interagency Group (2016). Minimum values reflect a 5 percent discount rate and the average of the damages distribution, while maximum values reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

U.S. costs are calculated as 15 percent of global costs (the midpoint of the suggested range in Interagency Working Group 2010).

Source: NERA calculations as explained in text

Table 4. Differences in Present Values of Social Costs of Carbon, Relative to the MSA Case, 2019-2048 (2019$ Millions)

	MSA	All Place		Moapa		SBS		Arevia	
Base	-	$38 to	$961	$30 to	$793	$28 to	$703	$16 to	$315
All Eligible	-	$45 to	$1,127	$29 to	$595	$28 to	$513	$15 to	$120

Note: All values are present values as of January 1, 2019 in millions of dollars for the period 2019-2048 based on values reported by Interagency Group (2016). Minimum values reflect a 5 percent discount rate and the average of the damages distribution, while maximum values reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

U.S. costs are calculated as 15 percent of global costs (the midpoint of the suggested range in Interagency Group 2010).

Source: NERA calculations as explained in text

21. Q. PLEASE COMMENT ON THE DIFFERENCES IN SOCIAL COSTS OF CARBON DIOXIDE EMISSIONS IN THESE CASES.

A. Under both load forecasts, the MSA case has the lowest social costs of carbon and the All Placeholder case has the highest social cost of carbon. The Arevia case and the Moapa case have similar social costs of carbon between these two cases.

22. Q. COULD YOU COMMENT ON THESE ESTIMATES OF THE SOCIAL COST OF CARBON AND THEIR RELATIONSHIP TO OTHER ENVIRONMENTAL COSTS?

A. I have in prior IRP's noted that the global values developed by the Interagency Working Group are not comparable to the other environmental costs 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 discount rates used to calculate the present value of the other environmental costs; and (c) the Interagency Working Group values are based upon global damages rather than U.S. or Nevada-specific damages.

VII. ASSESSMENT OF OTHER ENVIRONMENTAL COSTS

23. Q. DID YOU CONSIDER THE COSTS OF ENVIRONMENTAL IMPACTS OTHER THAN AIR EMISSIONS?

A. Yes, I also considered potential environmental impacts related to water quality, solid waste disposal, and land use in Nevada. I concluded that environmental costs related to these categories are not likely to be significant relative to the estimated environmental costs of air emissions. Thus, I have not included values for these other environmental costs in my analysis.

VIII. ASSESSMENT OF ADDITIONAL WATER CONSUMPTION COSTS NOT INCLUDED IN THE PWRR

24. Q. PLEASE SUMMARIZE YOUR METHODOLOGY FOR ESTIMATING THE ADDITIONAL COSTS OF WATER CONSUMPTION.

A. I estimated the potential additional costs of water consumption based upon the value of water use that is not included in the PWRR using plant-specific information on water consumption and water ownership from the Company. I developed proxies for existing and future NV Energy plants based on historic information on agricultural, municipal, and groundwater values in Nevada. The additional costs of water are based upon water use from wells owned by the Companies and do not include water that is leased or purchased, since the value of leased or purchased water is presumed to be included in the PWRR. In addition, no additional water costs are calculated for power purchased by the Companies through contracts or spot market transactions because I assume that all water costs are included in the prices that the Companies pay and thus are included in the PWRR. Similarly, no additional water costs are calculated for any power purchase agreements because I assume that the costs of any water that is used by third-party electricity generators—whether these are actual costs to the generators or opportunity costs of using their own water supply—will be included in the price paid by the Companies and thus in the PWRR. The methodology and data I used are described in detail in the NERA Report.

25. Q. PLEASE SUMMARIZE YOUR ESTIMATES OF THE ADDITIONAL COSTS OF WATER CONSUMPTION FOR THE FIVE RESOURCE CASES.

A. Table 5 shows the estimated additional costs of water consumption (i.e., the added costs beyond those already included in the PWRR) for the five resource cases under the Base and All Eligible load forecasts.

Table 5. Present Value of Additional Water Cost, 2019-2048 (2019$ Millions)

	MSA	All Placeholder	Moapa	SBS	Arevia
Base	$11.6	$11.5	$11.5	$11.5	$12.0
All Eligible	$7.9	$8.7	$8.4	$8.4	$8.1

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy.

26. Q. PLEASE COMMENT ON DIFFERENCES IN ADDITIONAL WATER COSTS AMONG THE CASES.

A. Table 6 shows the differences in estimates of additional costs of water consumption for the Base and All Eligible load forecasts relative to the MSA case. Under both policy scenarios, the Arevia case would have somewhat higher additional water costs than the MSA case. The remaining cases would all have higher or lower additional water costs than the MSA case dependent on the load forecast. Note that all of these differences are quite small, less than $1 million.

Table 6. Present Value of Differences in Additional Water Costs, Relative to MSA Case, 2019-2048 (2019$ Millions)

	MSA	All Placeholder	Moapa	SBS	Arevia
Base	-	-$0.1	-$0.2	-$0.2	$0.4
All Eligible	-	$0.8	$0.5	$0.5	$0.2

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy.

IX. ASSESSMENT OF TOTAL ENVIRONMENTAL COSTS

27. Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF THE TOTAL ENVIRONMENTAL COSTS OF THE ALTERNATIVE CASES.

A. Table 7 summarizes my estimates of total environmental costs for the five resource cases under the Base load forecast. The values for the social costs of carbon include ranges from the smallest values I calculated (i.e., the global values based on a 5% discount rate) to the largest values I calculated (global values based on 3% discount rate and using the 95th percentile values). Table 8 shows the differences in total environmental costs relative to the MSA case. Table 9 and Table 10 present the equivalent information for the cases under the All Eligible load forecast.

Table 7. Present Values of Total Environmental Costs Under the Base Load Forecast, 2019-2048 (2019$ Millions)

	MSA	All Placeholder	Moapa	SBS	Arevia
Conventional Air Emission Costs	$179.0	$184.5	$183.2	$182.8	$180.6
Additional Water Costs	$11.6	$11.5	$11.5	$11.5	$12.0
Social Costs of Carbon	$1,403.3 to $33,751.1	$1,441.4 to $34,712.3	$1,433.6 to $34,544.5	$1,431.8 to $34,454.4	$1,419.8 to $34,065.9
Total Environmental Cost	$1,594.0 to $33,941.7	$1,637.5 to $34,908.3	$1,628.2 to $34,739.2	$1,626.0 to $34,648.7	$1,612.5 to $34,258.6

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.
The SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

Table 8. Present Values of Differences in Total Environmental Costs Under the Base Load Forecast, Relative to the MSA Case, 2019-2048 (2019$ Millions)

	MSA	All Placeholder	Moapa	SBS	Arevia
Conventional Air Emission Costs	-	$5.6	$4.2	$3.8	$1.7
Additional Water Costs	-	-$0.1	-$0.2	-$0.2	$0.4
Social Costs of Carbon	-	$38.1 to $961.1	$30.2 to $793.4	$28.4 to $703.3	$16.5 to $314.8
Total Environmental Cost	-	$43.5 to $966.6	$34.3 to $797.5	$32.1 to $707.0	$18.5 to $316.8

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.
The SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

Table 9. Present Values of Total Environmental Costs Under the All Eligible Load Forecast, 2019-2048 (2019$ Millions)

	MSA	All Placeholder	Moapa	SBS	Arevia
Conventional Air Emission Costs	$148.5	$153.7	$151.0	$150.6	$150.0
Additional Water Costs	$7.9	$8.7	$8.4	$8.4	$8.1
Social Costs of Carbon	$1,153.6 to $27,978.4	$1,198.3 to $29,105.1	$1,182.6 to $28,573.3	$1,181.1 to $28,491.7	$1,168.9 to $28,098.8
Total Environmental Cost	$1,310.0 to $28,134.8	$1,360.8 to $29,267.5	$1,342.0 to $28,732.7	$1,340.1 to $28,650.7	$1,327.0 to $28,256.8

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.
The SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

Table 10. Present Values of Differences in Total Environmental Costs Under the All Eligible Load Forecast, Relative to the MSA Case, 2019-2048 (2019$ Millions)

	MSA	All Placeholder	Moapa	SBS	Arevia
Conventional Air Emission Costs	-	$5.1	$2.4	$2.0	$1.4
Additional Water Costs	-	$0.8	$0.5	$0.5	$0.2
Social Costs of Carbon	-	$44.8 to $1,126.8	$29.0 to $595.0	$27.6 to $513.3	$15.4 to $120.4
Total Environmental Cost	-	$50.8 to $1,132.7	$32.0 to $597.9	$30.1 to $515.9	$17.0 to $122.0

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.
The SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

28. Q. PLEASE COMMENT ON THE DIFFERENCES IN TOTAL ENVIRONMENTAL COSTS.

A. These results indicate that the total environmental costs are lowest for the MSA case. In contrast, the total environmental costs are noticeably larger for the All Placeholder case. These conclusions apply to both load forecasts.

X. ECONOMIC IMPACTS

29. Q. PLEASE SUMMARIZE THE CURRENT REGULATIONS RELATED TO EVALUATING THE ECONOMIC IMPACTS OF INTEGRATED RESOURCE PLANS IN NEVADA.

A. Section 704.9357 of the NAC requires the Company to assess the "net economic benefits" of resource plans reflecting "both the positive and negative changes." Section 704.9357 specifies that benefits to be calculated include in-state expenditures related to capital, supplies, wages, fees, and taxes associated with the resource plans. These expenditures would all produce positive economic impacts. The regulation does not include any specific language on how to assess the negative economic impacts of higher electricity prices.

30. Q. WHAT MODEL DID YOU USE TO ESTIMATE ECONOMIC IMPACTS FOR THIS ANALYSIS?

A. This analysis uses the model developed by Regional Economic Models, Inc. ("REMI") to provide comprehensive estimates of economic impacts for the alternative resource plans, including the positive effects of expenditures in Nevada as well as the potential negative effects of greater electricity rates under more expensive plans.

31. Q. PLEASE SUMMARIZE THE SOURCES OF INFORMATION YOU USED TO ASSESS THE ECONOMIC IMPACTS OF THE RESOURCE PLANS.

A. I relied on several sources of information as discussed in the NERA Report, including information provided by the Companies as well as data from the EIA. As described in the NERA Report, the Companies provided information including data on overall construction costs, the timing of construction costs, fuel costs and other operating costs for the various facilities, as well as additional information on electricity forecasts, which enabled the development of both positive and negative economic impacts. I used cost data from EIA for renewable projects to assess the economic benefits in Nevada of the Companies' renewable power purchase agreements. The Companies provided data related to projected electricity revenues from 2019 to 2048, dates that represent the start and end points for the economic impact analysis.

I used this information to develop inputs for REMI. The REMI inputs include estimates of the direct expenditures due to the various cases, including construction and annual operating and maintenance expenditures, as well as the electricity revenue requirements for various customer classes under the cases.

32. Q. PLEASE SUMMARIZE THE BASELINE OR REFERENCE SCENARIO YOU USED AND THE MEASURES YOU USED TO DETERMINE ECONOMIC IMPACTS.

A. REMI modeling includes a "baseline" or reference forecast, including assumptions on which NV Energy resource plan and which carbon price scenario is consistent with that reference forecast. I assume that the All Placeholder case and the Base Load forecast are consistent with the REMI reference forecast, since these seem to involve the least changes to NV Energy's generation fleet (and thus seem to most closely approximate what resources might be implicit in REMI's reference scenario). These assumptions mean the inputs to the REMI model are not the absolute values for expenditures and revenue requirements but rather the *differences* between expenditures and revenue requirements for each of the cases relative to the All Placeholder case.

I first develop the REMI model results, which provide estimates of how the Nevada economy would grow under the primary cases, under both the Base Load Forecast scenario and under the All Eligible Load Forecast scenario. As discussed below, the growth of the Nevada economy is broadly similar for all of the resource plans. Then I develop tables that compare the *differences* in REMI model results among the additional cases. As with the environmental costs, I express the differences relative to the Companies' preferred plan (the MSA case). Note that using the MSA case to compare REMI model *results* is not inconsistent with using the All Placeholder case as the reference scenario for purpose developing the REMI model *inputs*.

I characterize the "economic impacts" related to four impact categories: (1) gross state product, (2) personal income, (3) state and local tax revenue, and (4) employment. As discussed in the NERA Report, state and local tax revenue is calculated by NERA based on outputs from the REMI model, and the other three impact categories come directly from the REMI model for each year of the analysis period.

33. Q. PLEASE SUMMARIZE THE INPUTS TO YOUR ECONOMIC IMPACTS ANALYSIS.

A. It is useful to provide results first under the Base demand forecast and then under the All Eligible demand forecast. Table 11 and Table 12 show the average annual expenditures for the economic impact analysis under the Base forecasts over the period from 2019 to 2048 compared to the All Placeholder case (which as noted is the case presumed to be consistent with REMI's reference case). Only expenditures that occur in Nevada are included in these calculations because of the focus on estimating the economic impacts of alternative plans in Nevada. As discussed in the NERA report, these values exclude certain categories of expenditures, such as spot market purchases, because those expenditures are assumed to flow to power producers outside Nevada (and thus not generate positive economic impacts in Nevada). Note that these average annual values over the 30-year period do not reflect differences in timing of expenditures over the 30-year period.

Table 11. Average Annual Total Expenditures Under the Base Load Forecast, Relative to the All Placeholder Case, 2019-2048 (2019$ Millions)

	All Placeholder	Moapa	SBS	Arevia	MSA
Construction	-	$19	$13	$26	$60
Fuel	-	-$2	-$5	-$12	-$18
O&M	-	$2	$5	$11	$16
Total	-	**$19**	**$13**	**$25**	**$58**

Notes: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.

Table 12. Average Annual Total Expenditures Under the All Eligible Load Forecast, Relative to the All Placeholder Case, 2019-2048 (2019$ Millions)

	All Placeholder	Moapa	SBS	Arevia	MSA
Construction	-	$51	$44	$57	$88
Fuel	-	-$12	-$14	-$25	-$24
O&M	-	$8	$10	$8	$18
Total	-	**$47**	**$39**	**$40**	**$82**

Notes: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars. Real annual values were converted to nominal annual values using inflation rate information, as provided by NV Energy.

Table 13 and Table 14 show the average annual Companies' projected electricity revenues from 2019 to 2048 apportioned by customer class, compared to the revenue of the MSA case. This information is provided under both the Base and All Eligible load forecasts.

Table 13. Average Annual Electricity Revenue by Customer Under the Base Load Forecast, Relative to the All Placeholder Case, 2019-2048 (2019$ Millions)

	All Placeholder	Moapa	SBS	Arevia	MSA
Total	**-**	**-$8**	**-$12**	**-$29**	**-$44**
Residential	-	-$3	-$5	-$14	-$19
Commercial	-	-$2	-$3	-$7	-$11
Industrial	-	-$3	-$4	-$8	-$13

Notes: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.

Table 14. Average Annual Electricity Revenue by Customer Under the All Eligible Load Forecast, Relative to the All Placeholder Case, 2019-2048 (2019$ Millions)

	All Placeholder	Moapa	SBS	Arevia	MSA
Total	**-**	**-$2**	**-$6**	**-$26**	**-$36**
Residential	-	-$1	-$3	-$12	-$17
Commercial	-	$0	-$1	-$6	-$9
Industrial	-	$0	-$2	-$7	-$10

Notes: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars. Dollar year conversions are based on inflation rate information, as provided by NV Energy.

34. Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ECONOMIC IMPACTS ANALYSIS.

A. As with the REMI inputs, it is useful to summarize the REMI results first under the Base demand forecast and then under the All Eligible demand forecast. Table 15 displays the growth in the Nevada economy from 2018 to seven future years (2019, 2020, 2021, 2022, 2023, 2035, and 2048) for the five resource cases under the Base load forecast scenario. The REMI modeling results show substantial growth across the economic impacts metrics for each of the cases. These results indicate that growth in the Nevada economy would be similar under the five cases, although there are differences in the economic impacts among the cases in various years.

Table 15. Growth in Nevada Economy Under the Base Load Forecast, 2019-2048

	Nevada Economic Impacts Compared to 2018						
	2019	2020	2021	2022	2023	2035	2048
MSA							
Gross State Product (millions of 2019 dollars)	5,307	9,054	11,859	15,264	21,257	56,637	105,672
Personal Income (millions of 2019 dollars)	6,134	11,731	16,415	21,156	26,246	69,049	124,705
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,137	2,651	6,974	12,595
Employment (total jobs)	29,869	36,288	34,373	36,908	62,992	51,390	179,648
All Placeholder							
Gross State Product (millions of 2019 dollars)	5,307	9,050	11,857	14,500	17,100	56,341	105,206
Personal Income (millions of 2019 dollars)	6,134	11,729	16,414	20,631	23,399	68,869	124,352
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,084	2,363	6,956	12,560
Employment (total jobs)	29,869	36,249	34,349	29,070	21,393	48,546	176,294
Moapa							
Gross State Product (millions of 2019 dollars)	5,307	9,051	11,857	15,260	17,147	56,452	105,577
Personal Income (millions of 2019 dollars)	6,134	11,729	16,414	21,153	23,425	68,952	124,607
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,136	2,366	6,964	12,585
Employment (total jobs)	29,869	36,250	34,350	36,865	21,782	49,471	179,046
SBS							
Gross State Product (millions of 2019 dollars)	5,307	9,052	11,858	14,502	18,303	56,412	105,280
Personal Income (millions of 2019 dollars)	6,134	11,730	16,414	20,632	24,228	68,933	124,411
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,084	2,447	6,962	12,566
Employment (total jobs)	29,869	36,268	34,361	29,091	33,493	49,126	176,805
Arevia							
Gross State Product (millions of 2019 dollars)	5,307	9,052	11,857	14,502	20,010	56,643	105,218
Personal Income (millions of 2019 dollars)	6,134	11,730	16,414	20,632	25,398	69,070	124,388
State & Local Tax Revenue (millions of 2019 dollars)	620	1,185	1,658	2,084	2,565	6,976	12,563
Employment (total jobs)	29,869	36,267	34,360	29,089	50,609	51,021	176,306

Notes: The All Placeholder case (under the Base load forecast scenario) is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other four cases are in comparison to this plan. Employment values include full time and part time jobs.

Table 16 displays estimates of growth for selected years in Nevada gross state product, personal income, state tax revenue and employment compared to those of the MSA case under the Base load forecast scenario. The MSA case shows the greatest economic impacts in the earlier years for each of the economic outcomes. In 2035, however, GSP, personal income, and tax revenue would be slightly greater under the Arevia case than under the MSA case.

Table 16. Growth in Nevada Economy Under the Base Load Forecast, Relative to the MSA Case, 2019-2048

	Nevada Economic Impacts Compared to 2018						
	2019	**2020**	**2021**	**2022**	**2023**	**2035**	**2048**
MSA							
Gross State Product (millions of 2019 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2019 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2019 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
All Placeholder							
Gross State Product (millions of 2019 dollars)	0	-4	-2	-764	-4,157	-296	-466
Personal Income (millions of 2019 dollars)	0	-2	-1	-525	-2,847	-180	-353
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-288	-18	-36
Employment (total jobs)	0	-39	-24	-7,838	-41,599	-2,844	-3,354
Moapa							
Gross State Product (millions of 2019 dollars)	0	-3	-2	-4	-4,110	-185	-95
Personal Income (millions of 2019 dollars)	0	-2	-1	-3	-2,821	-97	-98
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	0	-285	-10	-10
Employment (total jobs)	0	-38	-23	-43	-41,210	-1,919	-602
SBS							
Gross State Product (millions of 2019 dollars)	0	-2	-1	-762	-2,954	-225	-392
Personal Income (millions of 2019 dollars)	0	-1	-1	-524	-2,018	-116	-294
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-204	-12	-30
Employment (total jobs)	0	-20	-12	-7,817	-29,499	-2,264	-2,843
Arevia							
Gross State Product (millions of 2019 dollars)	0	-2	-2	-762	-1,247	6	-454
Personal Income (millions of 2019 dollars)	0	-1	-1	-524	-848	21	-317
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-86	2	-32
Employment (total jobs)	0	-21	-13	-7,819	-12,383	-369	-3,342

Notes: The All Placeholder case (under the Base load forecast scenario) is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other four cases are in comparison to this plan. Employment values include full time and part time jobs.

Table 17 displays the growth in the Nevada economy from 2018 to seven future years (2019, 2020, 2021, 2022, 2023, 2035, and 2048) for the five resource cases under the Base load forecast scenario. The REMI modeling results show substantial growth across the economic impacts metrics for each of the cases. These results indicate that growth in the Nevada economy would be similar under the five cases, although there are differences in the economic impacts among the cases in various years.

Table 17. Growth in Nevada Economy Under the All Eligible Forecast, 2019-2048

	Nevada Economic Impacts Compared to 2018						
	2019	2020	2021	2022	2023	2035	2048
MSA							
Gross State Product (millions of 2019 dollars)	5,308	9,040	11,845	15,257	21,256	56,469	105,626
Personal Income (millions of 2019 dollars)	6,134	11,763	16,450	21,200	26,295	68,969	124,722
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,141	2,656	6,966	12,597
Employment (total jobs)	29,871	36,106	34,151	36,734	62,832	49,350	178,233
All Placeholder							
Gross State Product (millions of 2019 dollars)	5,308	9,036	11,843	14,493	17,082	56,570	105,321
Personal Income (millions of 2019 dollars)	6,134	11,761	16,448	20,675	23,436	69,088	124,456
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,088	2,367	6,978	12,570
Employment (total jobs)	29,871	36,067	34,127	28,892	21,043	49,937	176,089
Moapa							
Gross State Product (millions of 2019 dollars)	5,308	9,037	11,843	15,254	17,129	56,697	105,804
Personal Income (millions of 2019 dollars)	6,134	11,761	16,448	21,198	23,461	69,206	124,800
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,141	2,370	6,990	12,605
Employment (total jobs)	29,871	36,068	34,129	36,692	21,432	50,906	179,702
SBS							
Gross State Product (millions of 2019 dollars)	5,308	9,038	11,844	14,495	18,286	56,679	105,432
Personal Income (millions of 2019 dollars)	6,134	11,762	16,449	20,676	24,266	69,147	124,548
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,088	2,451	6,984	12,579
Employment (total jobs)	29,871	36,086	34,139	28,913	33,151	50,743	176,898
Arevia							
Gross State Product (millions of 2019 dollars)	5,308	9,038	11,844	14,495	20,010	56,451	105,302
Personal Income (millions of 2019 dollars)	6,134	11,762	16,449	20,676	25,452	68,965	124,477
State & Local Tax Revenue (millions of 2019 dollars)	620	1,188	1,661	2,088	2,571	6,965	12,572
Employment (total jobs)	29,871	36,085	34,138	28,911	50,477	49,149	175,852

Notes: The All Placeholder case (under the Base load forecast scenario) is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other four cases are in comparison to this plan. Employment values include full time and part time jobs.

Table 18 displays estimates of growth for selected years in Nevada gross state product, personal income, state tax revenue and employment compared to those of the MSA case under the All Eligible load forecast scenario. The results indicate that the MSA case shows the greatest economic growth for all four metrics (GSP, personal income, tax revenue, and employment) under the All Eligible load forecast in the years up to 2023. In contrast, the All Placeholder, Moapa, and SBS cases have noticeably larger growth in all metrics in 2035, and the Moapa case continues to have greater growth in all metrics in 2048.

Table 18. Growth in Nevada Economy Under the All Eligible Load Forecast, Relative to the MSA Case, 2019-2048

	Nevada Economic Impacts Compared to 2018						
	2019	2020	2021	2022	2023	2035	2048
MSA							
Gross State Product (millions of 2019 dollars)	-	-	-	-	-	-	-
Personal Income (millions of 2019 dollars)	-	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2019 dollars)	-	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-	-
All Placeholder							
Gross State Product (millions of 2019 dollars)	0	-4	-2	-764	-4,174	101	-305
Personal Income (millions of 2019 dollars)	0	-2	-2	-525	-2,859	119	-266
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-289	12	-27
Employment (total jobs)	0	-39	-24	-7,842	-41,789	587	-2,144
Moapa							
Gross State Product (millions of 2019 dollars)	0	-3	-2	-3	-4,127	228	178
Personal Income (millions of 2019 dollars)	0	-2	-2	-2	-2,834	237	78
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	0	-286	24	8
Employment (total jobs)	0	-38	-22	-42	-41,400	1,556	1,469
SBS							
Gross State Product (millions of 2019 dollars)	0	-2	-1	-762	-2,970	210	-194
Personal Income (millions of 2019 dollars)	0	-1	-1	-524	-2,029	178	-174
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-205	18	-18
Employment (total jobs)	0	-20	-12	-7,821	-29,681	1,393	-1,335
Arevia							
Gross State Product (millions of 2019 dollars)	0	-2	-1	-762	-1,246	-18	-324
Personal Income (millions of 2019 dollars)	0	-1	-1	-524	-843	-4	-245
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	-53	-85	0	-25
Employment (total jobs)	0	-21	-13	-7,823	-12,355	-201	-2,381

Notes: The All Placeholder case (under the Base load forecast scenario) is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other four cases are in comparison to this plan. Employment values include full time and part time jobs.

XI. CONCLUSION

35. Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

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Dr. David Harrison is a Managing Director at NERA Economic Consulting and co-head of NERA's global environment practice. He has extensive experience evaluating the economic effects of a wide range of policies and programs as a consultant, academic and government official.

Dr. Harrison has extensive experience over more than two decades evaluating the costs and benefits of air quality regulations under the Clean Air Act and other social regulatory policies, including various health and safety regulations. This experience includes evaluating the potential environmental benefits/damages associated with air emissions taking into account information on emissions, air quality concentrations, population exposure, and dose-response relationships. The various cost-benefit and cost-effectiveness studies have been done for a large number of sectors, including electricity, automobile, trucking, marine, chemical, iron and steel, petroleum, pulp and paper, small utility engines, small handheld equipment, snowmobiles, construction equipment, and others. He and his colleagues have worked closely with company officials and collaborated with various technical consultants in the development of information on these programs. The results of these analyses have been presented to company officials, government agencies, and the media.

Dr. Harrison has been active in the development and economic assessment of climate change policies around the world. He participated in the development or evaluation of major greenhouse gas programs and proposals in the United States, including those in California, the Northeast, the Midwest and various federal initiatives, as well as programs in Europe and Australia. He and his colleagues assisted the European Commission and the UK government with the design and implementation of the European Union Emissions Trading Scheme and national European programs related to climate change, renewable policies, and energy efficiency policies. He also has directed numerous projects for individual companies and trade associations—including those in electricity, oil and gas, refining, petrochemical, pulp and paper, cement, iron and steel, chemical, aluminum and other sectors—to evaluate the potential effects of climate change policies. Dr. Harrison and his colleagues have used NERA's proprietary energy-macroeconomic model (N_{ew}ERA) to evaluate the potential economic impacts of a U.S. carbon tax and to evaluate the potential economic impacts of federal regulations on carbon dioxide emissions from existing power plants. He has lectured frequently on climate change and related topics at numerous conferences in the United States and abroad.

Dr. Harrison has directed benefit-cost analyses for numerous electric power plants under Section 316(b) of the Clean Water Act and other regulations related to water quality. These have included facilities on the major water bodies, including the Atlantic Coast, the Great Lakes, the Pacific Coast, and various rivers. The power plants have included numerous nuclear and fossil units. These assessments have included estimates of the potential impacts on electricity cost and reliability using detailed electricity market models in various electricity regions of the United States. Dr. Harrison has testified regarding these cost-benefit assessments in numerous state workshops and administrative hearings. He also has assisted the Utility Water Act Group (UWAG), the Edison Electric Institute (EEI) and individual utilities in their evaluation of the EPA 316(b) regulations as well as of EPA effluent guideline regulations. He has presented the results of these assessments to senior EPA and OMB officials. Dr. Harrison was a co-signer of an Amicus Brief submitted to the Supreme Court of the United States regarding the comparison of benefits and costs under Section 316(b) of the Clean Water Act.

Dr. Harrison has directed numerous studies of the local and state economic impacts of policies and programs, including those related to transportation (airports, highways, airlines), housing and tourism activities, energy (power plants, natural gas pipelines and others), remediation (Superfund and other environmental remediation), manufacturing and mining activities (including mining, chemical, petrochemical, automotive, and many others), and large commercial and retail developments. He has developed estimates of the cumulative national and global contributions of these local and state contributions. The local and state analyses have used state-of-the-art model developed by Regional Economic Models, Inc. (REMI) and IMPLAN, as well as customized models developed by NERA based upon available data. These economic impact projects have been developed for numerous metropolitan areas within the U.S. and the rest of the world, for virtually all states in the U.S. as well as for individual countries in Africa, Europe, and the Caribbean. The results of these studies have been presented to numerous public and private groups as well as to the media.

On the national level, in addition to developing estimates of the cumulative national impacts on local economies, Dr. Harrison has worked with colleagues to develop macroeconomic assessments of the impacts of major national policies and programs on the U.S. and state economies. Assessments have included studies of the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan to reduce carbon dioxide emissions, EPA's potential regulations for ambient air quality standards for ozone, EPA's proposed effluent guidelines, cumulative effects of EPA air, coal combustion residuals, and cooling water regulations, and a potential carbon tax, all of which were based upon the use of the NewERA model, NERA's integrated electricity, energy and macroeconomic model.

Before joining NERA, Dr. Harrison was an Associate Professor at the John F. Kennedy School of Government at Harvard University, where he taught microeconomics, energy and environmental policy, cost-benefit analysis, transportation policy, regional economic development, and other courses for more than a decade. He also served as a Senior Staff Economist on the U.S. government's President's Council of Economic Advisors, where he had responsibility for environment and energy policy issues. He is the author or co-author of two books on environmental policy and numerous articles on various topics in professional journals.

Dr. Harrison received a Ph.D. in Economics from Harvard University, where he was a Graduate Prize Fellow. He holds a B.A. *magna cum laude* in Economics from Harvard College, where he was a member of Phi Beta Kappa, and a M.Sc. in Economics from the London School of Economics, where he was the Rees Jeffreys Scholar.

Education

Harvard University
Ph.D., Economics, 1974
M.A., Economics, 1972

London School of Economics and Political Science
M.Sc., Economics, 1968

Harvard University
B.A., Economics, *magna cum laude,* 1967

Professional Experience

National Economic Research Associates, Inc.
1988- *Managing Director, Senior Vice President, Vice President.* Directs projects in the economics of the environment, energy, transportation, regional economic development and other areas.

Putnam, Hayes & Bartlett, Inc.
1987-1988 *Senior Associate*. Directed projects in the economics of energy, antitrust, and other areas.

Dun & Bradstreet Technical Economic Services
1985-1987 *Director of Product Development*. Directed economic studies in energy, transportation, and industrial location.

John F. Kennedy School of Government, Harvard University
1980-1985 *Associate Professor*. Areas of instruction: microeconomics; benefit-cost analysis; environment; energy; natural resource economics; urban economics; public finance; transportation; law and economics. Participant, Harvard Faculty Project on Regulation. Faculty Steering Committee, Energy and Environmental Policy Center. Principal investigator in research grants.

President's Council of Economic Advisors

1979-1980 *Senior Staff Economist*. Worked with other White House staff and agency officials on domestic issues. Areas of responsibility included energy, environment and transportation. Principal staff on the Regulatory Analysis Review Group. Principal White House staff for the review of Administration policy regarding the automotive industry.

Department of City and Regional Planning, Harvard University

1974-1979 *Assistant and Associate Professor*. Areas of instruction: microeconomics; statistics; econometrics; transportation; environment; urban development; and housing policy. Participant, MIT-Harvard Joint Center for Urban Studies. Faculty Chairman, Concentration in Land Use and Environment.

National Bureau of Economic Research

1974 *Research Associate*. Co-author of benefit-cost study of automotive air pollution prepared by the National Academy of Sciences for the Committee on Public Works, U.S. Senate.

U.S. Department of Transportation

1973-1974 *Economist*. Performed economic studies of transportation issues, including urban mass transportation, automobile emission and safety programs, and highway finance.

Department of Economics, Harvard University

1970-1974 *Teaching Fellow and Assistant Head Tutor*. Areas of instruction: microeconomics; macroeconomics; econometrics; transportation; public finance; environmental policy; and housing policy.

The Urban Institute

1971 *Research Economist*. Participated in econometric studies as participant in the Program on Local Public Finance.

U.S. Department of Housing and Urban Development

1969 *Economist*. Participated in economic evaluations of HUD infrastructure programs, primarily the water and sewer grant program.

Honors and Professional Activities

Summa cum Laude, Senior Honors Thesis, Harvard University.

Phi Beta Kappa, Harvard University.

Rees Jeffreys Scholar in the Economics of Transport, London School of Economics.

Graduate Prize Fellowship, Harvard University.

Member, American Economic Association.

Member, Association of Environmental and Resource Economists.

Member, International Association of Energy Economists.

Member, Public Policy for Surface Freight Transportation Study, Transportation Research Board, National Research Council.

Member, Advisory Committee, Massachusetts Department of Environmental Quality Engineering.

Member, Peer Review Panel, National Acid Precipitation Assessment Program.

Member, Public Health and Socio-Economic Task Force, South Coast Air Quality Management District (Los Angeles).

Member, Marketable Permits Advisory Committee, South Coast Air Quality Management District (Los Angeles).

Member, Socioeconomic Technical Review Committee, South Coast Air Quality Management District (Los Angeles).

Member, Harvard Graduate Society Council.

Member, RECLAIM Advisory Committee (Los Angeles).

Member, Board of Trustees, Cambridge Health Alliance (Harvard Medical School Teaching Hospital).

Participant, Aspen Institute Dialogue on Climate Change.

Member, U.S. Government Accountability Office Expert Panel on International Greenhouse Gas Emissions Trading.

Consultant to the following public and private organizations:

U.S. Environmental Protection Agency; U.S. Department of Transportation; Massachusetts Port Authority; Organization for Economic Cooperation and Development (OECD, Paris); European Commission Directorate-General Environment; Civil Aeronautics Board; Italian Ministry of Environment; Massachusetts Department of Environmental Protection; UK Department of Transport; UK Department for Environment, Food and

Rural Affairs, UK Department of Trade and Industry, City of Chicago Department of Aviation; Conference Board of Canada; South Coast Air Quality Management District; Massachusetts Department of Environmental Management; and numerous state and local governments, trade associations, and private firms.

Reviewer for the following professional journals:

American Economic Review; Review of Economics and Statistics; Journal of Political Economy; Journal of Environmental Economics and Management; Journal of Urban Economics; Journal of Regional Science; Journal of Policy Analysis and Management; and Public Policy.

I. Publications

A. Books

Who Pays for Clean Air. Cambridge, MA: Ballinger Publishing Company, 1975.

The Automobile and the Regulation of Its Impact on the Environment (co-author). Norman, OK: Oklahoma University Press, 1975.

B. Articles and Published Reports

Economics in Environmental Decision-Making: US Environmental Protection Agency Provides for Site-Specific Cost-Benefit Analysis in Setting 316(b) Clean Water Standards (with Noah Kaufman), NERA Economic Consulting, May 2014.

"Economic Policy Instruments for Reducing Greenhouse Gas Emissions" (with Andrew Foss, Per Klevnas, and Daniel Radov), chapter in *Oxford Handbook of Climate Change*, edited by David Schlosberg, John Dryzek, and Richard Norgaard, August 2011.

Climate Change Risks and Opportunities: How Companies Can Develop Information to Comply with SEC Guidance Regarding Climate Change Disclosure (with Andrew Foss), NERA Economic Consulting, February 2010.

A Victory for Economic and Environmental Rationality: Supreme Court Allows Cost-Benefit Analysis in Setting Important Clean Water Act Standards, NERA Economic Consulting, May 2009.

What Every Company Should Do to Prepare for a Mandatory US Greenhouse Gas Cap-and-Trade Program, in *Climate Policy Economics Insights*, NERA Economic Consulting, March 2009.

Now the Hard Work: How to Get the "Biggest Bang for the Buck" from the Federal Economic Stimulus Package, NERA Economic Consulting, February 2009.

Evaluation of Borrowing as a Method to Contain Costs in a Greenhouse Gas Emissions Cap-and-Trade Program (with Albert Nichols), Electric Power Research Institute, December 2008.

"Using Emissions Trading to Combat Climate Change: Programs and Key Issues" (with Per Klevnas, Albert Nichols and Dan Radov) in *Environmental Law Reporter*, June 2008.

Complexities of Allocation Choices in a Greenhouse Gas Emissions Trading Program (with Per Klevnas and Dan Radov*),* International Emissions Trading Association (IETA), September 2007.

"State Restrictions on Mercury Trading Could Prove Expensive, Ineffective" (with James Johndrow) in *Natural Gas Electricity, Volume 24, Number 2.* Isabelle Cohen, Hoboken, NJ: Wiley Periodicals, Inc., September 2007.

"Experience for Member States in Allocating Allowances: United Kingdom" (with Dan Radov) in *Allocation in the European Emissions Trading Scheme.* A. Denny Ellerman, Barbara K. Buchner and Carlo Carraro, Cambridge, UK: Cambridge University Press, 2007.

Interactions of Cost-Containment Measures and Linking of Greenhouse Gas Emissions Cap-and-Trade Programs, Electric Power Research Institute, November 2006.

Interactions of Greenhouse Gas Emission Allowance Trading with Green and White Certificate Schemes, European Commission Directorate-General Environment, November 2005.

Carbon Markets, Electricity Prices and "Windfall Profits"—Emerging Information from the European Union Emissions Trading Scheme, Electric Power Research Institute, September 2005.

Economic Instruments for Reducing Ship Emissions in the European Union, European Commission, Directorate-General Environment, June 2005.

Evaluation of the Feasibility of Alternative Market-Based Mechanisms to Promote Low-Emission Shipping in European Union Sea Areas, European Commission, Directorate-General Environment, March 2004.

"Assessing the Financial Consequences to Firms and Households of a Downstream Cap-And-Trade Program to Reduce U.S. Greenhouse Gas Emissions" in *A Climate Policy Framework: Balancing Policy and Politics,* John A. Riggs, ed., Washington, DC: The Aspen Institute, 2004.

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Report on UK's Implementation of the CO_2 National Allocation Plan Under the European Union Greenhouse Gas Emissions Trading Programme, Department for Environment, Food and Rural Affairs, with AEA Technology and SPRU, July 2003.

"Ex Post Evaluation of the RECLAIM Emissions Trading Program for the Los Angeles Air Basin," National Policies Division, OECD Environment Directorate, June 2003.

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"A Groundbreaking Proposal: European Greenhouse Gas Emissions Trading," in *Infrastructure Journal*, August 2002.

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"Using the Hedonic Housing Value Method to Estimate the Benefits of Hazardous Waste Cleanup," (with J. Stock), U.S. Environmental Protection Agency, November 1984.

"Using the Averting Cost Method to Estimate the Benefits of Hazardous Waste Cleanup," (with M. O'Keeffe), U.S. Environmental Agency, November 1984.

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"Benefit-Cost Analysis of Environmental Regulation: Case Studies of Hazardous Air Pollutants," (with J. Haigh and A. Nichols), *Harvard Environmental Law Review* 8(1984).

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"Imports and the Future of the U.S. Automobile Industry," (with J. Gomez-Ibanez), *American Economic Review*, Papers and Proceedings 72 (May 1982).

"Who Loses from Reform of Environmental Regulation," (with P. Portney), in *Reform of Environmental Regulation*, Wesley Magat (Ed.). Cambridge, MA: Ballinger Publishing Company, 1982.

"Regulatory Reform in the Large and in the Small," (with P. Portney), in *Reforming Government Regulation*, LeRoy Graymer (Ed.). Beverly Hills, CA: Sage Publications, 1982.

"Making Ready for the Clean Air Act," (with P. Portney), *Regulation* 5(March/April 1981).

"Regulation and Distribution: An Agenda for Research," in *Creating an Agenda for Regulatory Research*, A. Ferguson (Ed.). Cambridge, MA: Ballinger Publishing Company, 1981.

"Cost-Benefit Analysis and the Regulation of Environmental Carcinogens," in *Management of Carcinogenic Risk*, W. Nicholson (Ed.). New York: New York Academy of Sciences, 1981.

"Distributional Objectives in Health and Safety Regulation," in *The Benefits of Health and Safety Regulation*, A. Ferguson (Ed.). Lexington, MA: D.C. Heath and Company, 1981.

"The Local Government Role in Energy Policy," (with M. Shapiro), in *Energy and Environment: Conflict and Resolution*, R. Axelrod (Ed.). Lexington, MA: D.C. Heath and Company, 1981.

"Simulating the Impacts of Transportation Policy on Urban Land Use," Discussion Paper, Department of City and Regional Planning, Harvard University, April 1979. (Presented at meeting of the Eastern Economics Association, May 1979.)

"Income and Urban Development," Discussion Paper, Department of City and Regional Planning, Harvard University, April 1979.

"Discussion of Robert C. Ellickson, 'Public Property Rights: Vicarious Intergovernmental Rights and Liabilities as a Technique for Correcting Intergovernmental Spillovers," in *Essays on the Law and Economics of Local Government*, D. Rubinfeld (Ed.). Washington, D.C: The Urban Institute, 1979.

"The Distribution of Benefits from Improvements in Urban Air Quality," (with D. Rubinfeld), Journal of Environmental Economics and Management 5(December 1978).

"The Impact of Transit Systems on Land Use Patterns in the Pre-Automobile Era," Discussion Paper, Department of City and Regional Planning, Harvard University, December 1978.

"The Air Pollution and Property Value Debate: Some Empirical Evidence," (with D. Rubinfeld), *Review of Economics and Statistics* 60(November 1978).

"Transportation Technology and the Dynamics of Urban Land Use Patterns," paper presented to the Conference on Urban Transportation, Planning, and the Dynamics of Land Use, Northwestern University, June 1978.

"Hedonic Housing Values and the Demand for Clean Air," (with D. Rubinfeld), *Journal of Environmental Economics and Management* 5(March 1978).

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"Reply to Michelle White's Comment on 'Cumulative Urban Growth and Urban Density Functions,'" (with J. Kain), *Journal of Urban Economics* 4(January 1977).

"Cumulative Urban Growth and Urban Density Functions," (with J. Kain), *Journal of Urban Economics* 1(January 1974).

II. Consulting Reports for Directed Projects

A. Climate Change

Evaluation of Alternative Passenger Car and Light Truck Corporate Average Fuel Economy (CAFE) Standards for Model Years 2021-2026, prepared for Alliance of Automobile Manufacturers, October 2018.

Environmental Costs and Economic Impacts of the 2018 Integrated Resource Plan, prepared for Nevada Power Company, June 2018.

Environmental Costs and Economic Impacts of 100 MW Generic Technology/Resource Options (Supplemental Report to 2016 IRP), prepared for Sierra Pacific Power Company, September 2016.

Environmental Costs and Economic Impacts of the 2016 Integrated Resource Plan, prepared for Sierra Pacific Power Company, June 2016.

Potential Electricity and Energy Price Outcomes under EPA's Federal Plan Alternatives for the Clean Power Plan, prepared for Group of Energy-Intensive Industry Associations, January 2016.

Energy and Consumer Impacts of EPA's Clean Power Plan, prepared for the American Coalition for Clean Coal Electricity, November 2015.

Environmental Costs and Economic Impacts of the 2015 Integrated Resource Plan, prepared for Nevada Power Company, June 2015.

Investing in a Time of Climate Change, prepared with Mercer for a group of asset-owner and manager partners, June 2015.

Impacts of the EPA Clean Power Plan Building Blocks on Texas Energy Markets, prepared for Luminant, November 2014.

Potential Energy Impacts of the EPA Proposed Clean Power Plan, prepared for the American Coalition for Clean Coal Electricity and other organizations, October 2014.

A Carbon Dioxide Standard for Existing Power Plants: Impacts of the NRDC Proposal, prepared for the American Coalition for Clean Coal Electricity, March 2014.

Linkage of a Potential South African GHG Cap and-Trade Program: Initial Scoping Study," prepared for Sasol, June 13, 2013.

Environmental and Economic Impacts of the 2013 Integrated Resource Plan, prepared for Sierra Pacific Power Company, June 2013.

Economic Outcomes of a U.S. Carbon Tax, prepared for National Association of Manufacturers, February 26, 2013.

Environmental and Economic Impacts of the Second Amendment to the 2010 Integrated Resource Plan, prepared for Sierra Pacific Power, August 2012.

Analysis of EPA's Proposed GHG, New Source Performance Standard for Electric Generating Units, prepared for American Coalition for Clean Coal Electricity, June 25, 2012

Environmental and Economic Impacts of the 2012 Integrated Resource Plan, prepared for Nevada Power Company, June 2012.

Evaluation of Incentives in International Sectoral Crediting Mechanisms, prepared for Enel S.p.A., October 2011.

Environmental and Economic Impacts of the First Amendment Supplemental Filing to the 2009 Integrated Resource Plan, prepared for Nevada Power Company, October 2011.

Environmental Costs and Economic Impacts of the Second Amendment to the 2009 Integrated Resource Plan, prepared for Nevada Power Company, August 2011.

Environmental Costs and Economic Impacts of the 2010 Integrated Resource Plan, prepared for Sierra Pacific Power Company, July 2010.

Environmental Costs and Economic Impacts of the 2009 Integrated Resource Plan, prepared for Nevada Power Company, February 2010.

Follow-up letter to US Environmental Protection Agency Clarifying Key Conclusions from Review of EPA's Approach to Aggregating Emissions Across Time in Proposed Revisions of Renewable Fuel Standards, prepared on behalf of Growth Energy, January 2010.

Review of EPA's Approach to Aggregating Emissions across Time in Proposed Revisions of Renewable Fuel Standards, prepared for Growth Energy for submission to U.S. EPA, Docket ID No. EPA-HQ-OAR-2005-0161, September 2009.

Differentiation among Batches of Conventional Biofuels based on Greenhouse Gas Emissions, prepared for Growth Energy, September 2009.

Impacts of Waxman-Markey Bill on US Refiners: Preliminary Estimates, prepared for major industrial sector, July 2009.

Effects of Waxman-Markey on Natural Gas and Electricity Businesses: Phase 1, prepared for a Midwest utility, July 2009.

Impacts of the California Greenhouse Gas Emission Standards on Motor Vehicle Sales, prepared for the Alliance of Automobile Manufacturers, April 2009.

Accounting for Differences in the Timing of Emissions in Calculating Carbon Intensity for the California Low Carbon Fuels Standard, prepared for the Renewable Fuels Association, April 2009.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, March 2009.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, March 2009.

Evaluation of Alternative Benchmarked Sector-Level Allocation Formulas, prepared for a major U.S. industrial trade group, October 2008.

Evaluation of NHTSA's Benefit-Cost Analysis of 2011-2015 CAFE Standards, prepared for the Alliance of Automobile Manufacturers, July 2008.

Impacts of Climate Change Policies Using the NERA Carbon Financial Impacts Model (Phase 2 Study, prepared for a major U.S. industrial manufacturer, June 2008.

Effects of the Regional Greenhouse Gas Initiative on Regional Electricity Markets, prepared for AES and Dynegy, June 2008.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Nevada Power Company, May 2008.

Impacts of Potential Climate Change Policy using the NERA Carbon Financial Impacts Model, prepared for a major U.S. trade association, April 2008.

Market Conditions and the Pass-Through of Compliance Costs in a Carbon Emission Cap-and-Trade Program, prepared for Conoco Phillips, January 2008.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. industrial manufacturer, December 2007.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. energy company, November 2007.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. industrial manufacturer, October 2007.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. energy company, September 2007.

Environmental Costs and Economic Benefits of Electric Utility Resource Selection, prepared for Sierra Pacific Power Company, June 2007.

Evaluation of the Financial Impacts of Alternative Climate Change Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. energy company, March 2007.

Effectiveness of the California Light Duty Vehicle Regulations as Compared to Federal Regulations, in collaboration with Sierra Research, Inc. and Air Improvement Resource, Inc., prepared for the Alliance of Automobile Manufacturers, June 2007.

Financial Impacts of Potential Mandatory CO2 Cap-and-Trade Programs using the NERA Carbon Financial Impacts Model, prepared for a major U.S. trade association, January 2007.

Modeling the Fleet Population Effects of the Rhode Island Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, November 2005.

Review of Potential Expansion of the UK Phase II National Allocation Plan to the Petrochemical Sector, prepared for UK Department for the Environment, Food and Rural Affairs (DEFRA) and Department of Trade and Industry (DTI), November 2005.

The Impacts of CO_2 Prices on European Electricity Prices, prepared for Electricité de France (EDF), October 2005.

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Modeling the Fleet Population Effects of the Maine Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, October 2005.

Modeling the Fleet Population Effects of the New Jersey Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, September 2005.

Modeling the Fleet Population Effects of the Connecticut Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, September 2005.

Modeling the Fleet Population Effects of the Vermont Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, August 2005.

Modeling the Fleet Population Effects of the New York State Proposal to Reduce Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, July 2005.

Initial Review of Potential Expansion of the UK Phase 2 NAP to Additional CO_2 Sources, prepared for the Department for the Environment, Food and Rural Affairs, May 2005.

Environmental and Economic Impacts of the ARB Staff Proposal to Control Greenhouse Gas Emissions from Motor Vehicles, prepared for the Alliance of Automobile Manufacturers, September 2004. Submitted to the California Air Resources Board.

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Impacts of ZEV Sales Mandate on California Motor Vehicle Emissions: Responses to Comments of Air Resource Board Staff and Related Documents Provided as Part of the 15-Day Notice (with Sierra Research, Inc.), prepared for the Alliance of Automobile Manufacturers, November 2001.

KEPCO's Role in a Greenhouse Gas Emissions Trading Program, prepared for Kansai Electric Power Company, February 2001.

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The Timing of Plant Replacement and the Cost-Effectiveness of CO_2 Reductions from Two Canadian Utilities, prepared for Ontario Hydro and TransAlta Corporation, July 1996.

Strategic Environmental Issues Facing Fossil-Fired Electric Generating Plants in Canada, draft prepared for Ontario Hydro and TransAlta Corporation, June 1996.

Scoping Study to Assess the External Costs of Electric Utility Resource Selection in Minnesota, prepared for Otter Tail Power Company with assistance from Systems Applications International, March 1993.

Preliminary Draft Scoping Study to Assess Residual Emissions Valuation in Alberta, prepared for TransAlta Utilities Corporation, September 1992.

Distributional Effects of Economic Instruments for Environmental Policy, prepared for the U.S. Environmental Protection Agency and the Organization for Economic Cooperation and Development, May 1992.

Tradable Permits and Other Economic Incentives for Environmental Protection, prepared for The Canadian Electrical Association and presented at a Workshop on Tradable Permits, June 1990.

B. Economic Impact Assessment

Impacts of Digital Video Piracy on the U.S. Economy, prepared for the U.S. Chamber of Commerce, June 2019.

Economic Contributions of EmblemHealth and AdvantageCare Physicians to the New York City and New York State Economies, prepared for EmblemHealth, October 2018.

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Impacts of Continental Airlines Operations on the New York- New Jersey Regional Economy, prepared for Continental Airlines, November 2009.

Potential Jobs Impacts of Energy Efficiency Expenditures, prepared for Commonwealth Edison, December 2008.

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Before the Minnesota Public Utilities Commission, *Considerations in the Development of Externality Values,* direct testimony on behalf of Northern States Power Company In the Matter of the Establishment of Environmental Cost Values, Docket No. E-999/CI-93-583, November 1994.

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Before the Public Utilities Commission of the State of California, *External Benefits from Increasing Electric Vehicles in the Pacific Gas & Electric Service Territory,* testimony prepared on behalf of Pacific Gas & Electric Company In the Matter of the Order Instituting Investigation and Order Instituting Rulemaking to Develop Rules, Procedures, and Policies Governing Utility Involvement in the Market for Low-Emissions Vehicles, October 1993.

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Before the California Energy Commission ER-92 Hearing on Valuing Air Quality Impacts of Energy Resources, *Revised Damage-Based Values for Residual Emissions Valuation, (with M. B. Deming)*, testimony prepared on behalf of Southern California Edison Company, Sacramento, California, May 1992.

Before the State of California Energy Resources Conservation and Development Commission, *Valuing Air Quality Impacts of Alternative Energy Resources*, testimony prepared on behalf of Southern California Edison Company, Docket No. 90-ER-2, March 1992.

Before the California Energy Commission ER-92, *Group I Hearing Issues: Air Quality, (with Southern California Edison), 1992 Electricity Report,* testimony prepared on behalf of Southern California Edison Company, Docket No. 90-ER-92, submitted by Southern California Edison, November 1991.

Affidavit on Landing Fees at Logan International Airport, prepared on behalf of the defendant in *New England Legal Foundation, et al. v. Massachusetts Port Authority and National Business Aircraft Association, Inc., et al.*, United States District Court, District of Massachusetts, June 1988. (Also submitted to the U.S. Department of Transportation.)

Defendant's Expert Witness Disclosure on Summary of Damages Claimed by the State of Michigan for Fish Killed by the Luddington Pumped Storage Plant, prepared on behalf of Consumers Power Company and The Detroit Edison Company in *Frank J. Kelley, ex rel Michigan Natural Resources Commission; Michigan Department of Natural Resources; and Gordon Guyer, Director of the Michigan Department of Natural Resources v. Consumers Power Company and The Detroit Edison Company*, Case No. 86-57075-CE in the Circuit Court for the County of Ingham, June 1988.

IV. Presentations

A. Climate Change

"National Carbon Policies: Looking Backward and Looking Forward," presented at LSI Conference on Combating Climate Change in the Pacific Northwest, Seattle, Washington, June 6, 2018.

"Energy and Economic Impacts of the Clean Power Plan," presented to the American Coalition for Clean Coal Electricity, November 2015.

"A Carbon Dioxide Standard for Existing Power Plants: Impacts of the NRDC Proposal," presented to the American Coalition for Clean Coal Electricity, March 2014.

"Offsets in Potential EPA GHG Tradable Performance Standard for Existing Power Plants: Preliminary Assessment," Presentation to the Electric Power Research Institute Environment & Renewable Program Advisory Meeting, Kansas City, Missouri, September 24, 2013.

"The Interactions of Complementary Policies with a GHG Cap-and-Trade Program: The Case of Europe," presentation at the EPRI-IETA Joint Symposium, San Francisco, April 16, 2013.

"Incentives for International Sectoral Crediting Mechanisms," presented at the Workshop on New Market Mechanisms organized by the International Emissions Trading Association and Enel S.p.A., Brussels, October 13, 2011.

"The Copenhagen Conference: International Climate Policy and Implications for US Policy," presented at the Fenway Colleges Climate Change Teach-In, Washington, DC, February 25, 2010.

"U.S. Greenhouse Gas Cap-and-Trade Programs and Cost Containment," presented at the EUEC 2010 Energy & Environment Conference, AZ, Phoenix, February 1, 2010.

"Financial Implications of a US Cap-and-Trade Program for Sectors and Companies," presented at 2nd Annual Carbon Trading Summit, New York City, January 13, 2010.

"Lessons Learned from the European Union Emissions Trading Scheme," presented to California State Senate Select Committee on Climate Change and AB 32 Implementation, Sacramento, CA, January 7, 2010.

"Greenhouse Gas Emissions Cap-and-Trade Program: Key Design Elements," presented at the IETA Fall 2009 Symposium, Washington, DC, November 3, 2009.

"Compliance Flexibility in Domestic Greenhouse Gas Cap-and-Trade Programs," presented to the 9th Annual Workshop on Greenhouse Gas Emissions Trading sponsored by the Electric Power Research Institute, the International Energy Agency, and the International Emissions Trading Association, Paris, September 14, 2009.

"Allocation Decisions in the European Union Emissions Trading Scheme," presented to the California Economic and Allocation Advisory Committee, July 1, 2009.

"Economic Analysis of Waxman-Markey Climate Bill (ACES)," presented as part of Environmental Markets Association Webinar, June 4, 2009.

"Climate Policy Risks for Electric Utilities: Economic Modeling to Assist Utilities in Responding to Climate Change Programs," presented at the Utility Rate Case Conference organized by Law Seminars International, Las Vegas, NV, February 6, 2009.

"Cost-Containment in a U.S. Greenhouse Gas Cap-and-Trade Program," presented at the EEI Fall 2008 Legal Conference, Boston, October 30, 2008.

"Climate Change and Electricity Prices: What Should Electricity Companies Do," presented at the EUCI Conference on Electricity, Chicago, September 30, 2008.

"The EU Energy and Climate Package: Interactions between EU Policies and Targets and Implications for CO2 Price Uncertainty," presented at the IEA/IETA/EPRI 8th Annual Workshop on Greenhouse Gas Emissions Trading, Paris, September 23, 2008.

"European Union Emissions Trading Scheme: Overview and Implications for the U.S.," presented at the Second Carbon Trading Summit, New York, NY, June 24, 2008.

"Carbon Emissions Trading and Allocation: Complexities of Policy Choices," presented at the IETA/AIGN Workshop, Canberra, Australia, March 5, 2008.

"Climate Change: What Every Company Should Do to Get Ready for a Mandatory Emissions Trading Program," presented at NERA Economic Consulting Workshop, Sydney, Australia, March 4, 2008.

"Workshop on Carbon Emissions Trading: EU and US Experience and Implications for IP/Australia," presented before International Power, Melbourne, Australia, March 3, 2008.

"Design Elements for Potential Canadian GHG Cap-and-Trade Program," presented at the Cap and Trade Working Group Retreat, Toronto, Ontario, January 31, 2008.

"Allocation in the EU ETS: What Have We Learned?" presented at the MIT workshop on EU ETS, Washington, DC, January 24, 2008.

"Emissions Trading: Background, Prior Programs and Implications for a U.S. Carbon Cap-and-Trade Program," presented at ALI-ABA Course on Clean Air: Law, Policy and Practice, Washington, DC, November 9, 2007.

"Overview of the European Union Emissions Trading Scheme for Carbon Dioxide," presented at EEI's 2007 Fall Legal Conference, Napa, California, October 4, 2007.

"Evaluating the Financial Impacts of Potential Carbon Cap-and-Trade Programs on Electricity Companies: What Every Electricity Company Should Do to Get Ready for Mandatory Climate Change Policy," presented at the Carbon Constraint Conference, Chicago, September 13, 2007.

"EU ETS Allocation Options: Reconciling Complexities and Simplicity/Transparency," presented before the IETA-CEPS Climate Change Conference, Brussels, Belgium, June 26, 2007.

"Overview of Allocation Methodologies and Principles," presented before the European Climate Change Programme working group on emissions trading, Brussels, Belgium, May 21, 2007.

"Allocation Choices for a Carbon Trading Program," presented at the Carbon Expo, Cologne, Germany, May 3, 2007.

"Allocation Choices and International Considerations," presented to Senate staff members, Washington, DC, February 2, 2007.

"Carbon Financial Analyses for Electricity Companies," presented at the Electric Utilities Environmental Conference, Tucson, Arizona, January 23, 2007.

"Carbon Emissions and State Electric Utility Regulation," presented at the Electric Utilities Environmental Conference, Tucson, Arizona, January 22, 2007.

"European Union Emissions Trading Scheme for Carbon Dioxide: Lessons and Implications," presented at North America and The Carbon Markets Conference hosted by Point Carbon and Pew Center on Global Climate Change, Washington, DC, January 18, 2007.

"Policy Design Side By Side: What Elements Matter," presented at North America and the Carbon Markets Conference hosted by Point Carbon and Pew Center on Global Climate Change, Washington, DC, January 17, 2007.

"European Union," presented at North America and the Carbon Markets Conference hosted by Point Carbon and Pew Center on Global Climate Change, Washington, DC, January 17, 2007.

"Carbon Markets, Linking, and Cost Containment," presented at the IEA/IETA/EPRI 6th Annual Emissions Trading Workshop, Paris, France, September 27, 2006.

"Auctioning Experience in Other Sectors and Implications for Designing a Carbon Auction," presented at the IETA Workshop on Allocation Methodologies, Paris, France, September 25, 2006.

"European Carbon Markets and Implications for a US Carbon Constrained Future," presented at Preparing for a Carbon Constrained Future Conference hosted by Electric Utility Consultants, Inc., Arlington, Virginia, June 28, 2006.

"Overview of the European Union Emissions Trading Scheme," presented to staff of the Senate Committee on Energy and Natural Resources, Washington, DC, June 16, 2006.

"Policies to Address Potential EU ETS Impacts on Power Prices and Industrial Competitiveness," presented at the CEPS/IETA Climate Change Conference, Brussels, Belgium, May 30, 2006.

"Learning from Experience: First Year of the European CO_2 Emissions Trading Scheme," presented to New Prospects for Climate Change Regulation Panel organized by Harvard Law School, March 10, 2006.

"Carbon Policies and Electric Utility Rate Cases," presented at the Managing the Modern Utility Rate Case Conference organized by Law Seminars International, Las Vegas, NV, February 14, 2006.

"Beyond Cost: Carbon Markets, Electricity Prices and 'Windfall Profits,'" presented to Electric Utilities Environmental Conference, Tucson, AZ, January 23, 2006.

"European CO_2 Emissions Trading Scheme: First Year Accomplishments and Implications," presented at an International Emissions Trading Association side event at the 11th Conference of the Parties to the Kyoto Protocol, Montreal, December 5, 2005.

"Allocation Choices for a U.S. Carbon Dioxide Emissions Trading Scheme," presented to National Commission on Energy Policy, Workshop on Allowance Allocation, Washington, DC, September 30, 2005.

"Carbon Markets, Electricity Prices and Windfall Profits: Emerging Information on the European Union Emissions Trading Scheme" presented to IEA-IETA-EPRI Emissions Trading Workshop, Paris, September 27, 2005.

"U.S. State-level Climate Regimes: Lessons from the U.S. and Europe, presented to Fourth Annual Green Trading Summit, New York, NY, May 2, 2005.

"Overview of Allocation Choices: Alternatives and Implications," presented to Stakeholder Workshop, Regional Greenhouse Gas Initiative, Boston, MA, October 14, 2004.

"Emissions Trading: Concepts, Experience, Lessons, and Implications Greenhouse Gas Programs," presented to Iberdrola, Cambridge, MA, March 25, 2004.

"How CEPCO Can Gain from CO_2 Trading," presented to Chubu Electric Power Co., Inc., Nagoya, Japan, November 25, 2003.

"The Rise of Emissions Trading in Air Quality and Climate Change Policy," presented to EPRI Environmental Sector Council, San Antonio, Texas, September 12, 2003.

"Greenhouse Gas Emissions Trading and Firm Risk Management Behavior", presented to the ARPEL-IPIECA Workshop, A Practical Approach to Identifying Emission Reduction Opportunities: Examples under the Kyoto Mechanisms in Latin America and the Caribbean, San Jose, Costa Rica, December 3, 2002.

"Initial Allocations in Various Systems of Emissions Trading" presented to the Exploring New Approaches in Regulating Industrial Installations (ENAP) Workshop on Emissions Trading for NO_X and SOx in Europe, The Hague, Netherlands, November 22, 2002.

"Overview of Alternative Allocations for European GHG Trading Program," presented to IEA-EPRI-IETA Workshop on Greenhouse Gas Emissions Trading, Paris, September 17, 2002.

"Evaluation of Alternative Allocations for European GHG Trading Program," presented to IEA-EPRI-IETA Expert Meeting: Allocation of GHG Objectives, Paris, September 16, 2002.

"Greenhouse Gas Emission Trading Programs," presented to Chubu Electric Company, Cambridge, MA, July 16, 2002.

"Evaluation of Alternative Allocations for European GHG Trading Program," presented to Chubu Electric Company, Cambridge, MA, July 16, 2002.

"Corporate Strategies and Practices for GHG Emission Reduction," presented to Chubu Electric Company, Cambridge, MA, July 15, 2002.

"Emission Trading: Concepts, Experience, and Lessons from Non-Greenhouse Gas Programs," presented to Chubu Electric Company, Cambridge, MA, July 15, 2002.

"Prospects for the EU Greenhouse Gas Trading Program," presented to EPRI Global Climate Change Research Seminar, Washington, DC, June 4, 2002.

"Evaluation of Alternative Allocations for European GHG Trading Program," presented to European Commission, Brussels, Belgium, November 13, 2001.

"Evaluation of Alternative Allocations for European GHG Trading Program," presented to ENVECO, Brussels, Belgium, November 13, 2001.

"CO_2 Permit Allocations: Evaluation of Alternatives for the EC," presented to the European Commission, Brussels, Belgium, March 5, 2001.

"Setting Baselines for Greenhouse Gas Trading: Lessons from Experience," presented to United Nations Framework Convention on Climate Change, Bonn, Germany, June 10, 2000.

"Setting Baselines for Greenhouse Gas Programs: Lessons from Experience," presented at the EPRI Global Climate Change Research Seminar, Washington, DC, May 18, 2000.

"Emissions Trading and Developing Countries: Implications of U.S. Experience and World Bank Role," presented at World Bank – Energy Week 2000, Washington, DC, April 13, 2000.

"Domestic GHG Trading: Assessing Impacts on Electric Utilities," presented to Electric Power Research Institute, Washington, DC, February 17, 2000.

"Energy-Environmental Policy Integration & Coordination (E-EPIC), U.S. Economic Growth & Health," presented to Electric Power Research Institute, Washington, DC, May 13, 1999.

"Priorities for the Development of GHG Trading Programs: Implications of the United States Experience," presented to the EPRI Global Climate Change Area Meeting, San Diego, California, January 26, 1999.

"Priorities for the Development of GHG Trading Programs: Implications of the United States Experience," presented to the Air & Waste Management Association Specialty Conference on Global Climate Change, Washington, DC, October 14, 1998.

"International Greenhouse Gas Trading," presented to the American Council for Capital Formation, Washington, DC, September 23, 1998.

"International Greenhouse Gas Emission Trading: Promise and Performance," presented to the EPRI Global Climate Change Research Seminar, Washington, DC, May 27, 1998.

"International Greenhouse Gas Trading: A 'Silver Bullet' Train?" presented to Sidebar Meeting, United Nations Framework Convention on Climate Change, Bonn, Germany, October 23, 1997.

"International Greenhouse Gas Trading," presented to the American Council for Capital Formation Conference on Global Warming, Washington, DC, September 24, 1997.

"International Greenhouse Gas Trading," presented to the National Association of Manufacturers, Washington, DC, September 17, 1997.

"International Greenhouse Gas Trading," presented to the American Automobile Manufacturers Association, Washington, DC, May 1, 1997.

"Emission Trading: Alternative Approaches, Experience and Implications for CO_2," prepared for the AAMA Climate Change Task Force, Washington, DC, September 27, 1996.

"Treatment of Greenhouse Gas Emissions in Electric Utility Resource Planning," prepared for the Third Conference on External Costs, *Internalization of Social Costs of Energy Conservation and Transportation in the United States and Europe for a Sustainable Development*, Ladenburg, Germany, May 29, 1995.

"Distributive Impacts of Economic Instruments for Greenhouse Gas Abatement," presented at the Air & Waste Management Association International Specialty Conference *Global Climate Change: Science, Policy and Mitigation Studies*, Phoenix, Arizona, April 6, 1994.

"New Approaches for Controlling Global Warming," presented to the Conference on Global Warming, Vermont Law School, South Royalton, Vermont, February 16, 1990.

B. Economic Impact Assessments

"Economic Assessments at Tier 2 Superfund Sites," presented at The 34th Annual International Conference on Soils, Sediments, Water and Energy, Amherst, Massachusetts, October 15, 2018.

"Economic Impacts of a 65 ppb National Ambient Air Quality Standard for Ozone," Webinar, (with Anne E. Smith), prepared for the Association of Air Pollution Control Agencies, March 2, 2015.

"Cumulative Energy Market Impacts of Various Environmental Regulations," presented at Law Seminars International, Utility Rate Case Issues and Strategies 2013, Las Vegas, Nevada, February 21, 2013.

"Financial Implications of a US Cap-and-Trade Program for Sectors and Companies," presented at 2nd Annual Carbon Trading Summit, New York City, January 13, 2010.

"Evaluating the Impact of Future E.U. Chemical Policy on the French Economy," presented to REMI Northeast Policy Analysis and Users' Conference, Boston, MA, January 31, 2006.

"Background on NERA Study 'Socioeconomic Effects of the Niagara Power Project and Local NYPA Presence'," presented to Niagara Power Project Relicensing Stakeholder Meeting, Niagara Falls, NY, November 13, 2003.

"Economic Benefits to the Chicago Region from the Whitecap Energy System," presented to the Illinois Department of Natural Resources, Springfield, Illinois, January 30, 2001.

"Fueling Electricity Growth for a Growing Economy," presented to Edison Electric Institute, Palm Springs, California, January 13, 2000.

"Economic Impact Analyses with REMI: Two Case Studies," presented to the REMI Seminar, Miami, Florida, October 6, 1997.

"Impacts on the Hawaii Economy of Alternative Resource Plans for Oahu," presented to the Hawaiian Electric Company IRP Advisory Group, Honolulu, Hawaii, July 24, 1997.

"Economic and Environmental Effects in Maine of the Maritimes & Northeast Pipeline Project," presented to the Maine Economic Development Council, Rockland, Maine, February 12, 1997.

"Economic and Environmental Effects of the Maritimes & Northeast Pipeline Project," presented to a media conference and Editorial Boards of the *Bangor Daily News*, the *Portland Press Herald*, and the *Kennebec Journal*, Bangor and Augusta, Maine, November 21, 1996.

"Assessing the Economic Impacts of Alternative HECO Resource Plans," presented to the PSP&ED Advisory Group of the Hawaiian Electric Company, Honolulu, Hawaii, July 3, 1996.

"The Lake Calumet Airport and Chicago's Economic Future," presented to the Lake Calumet Airport Advisory Committee, Chicago, Illinois, July 2, 1991.

"Socioeconomic Impacts of Proposed Rule 431.2," prepared for Southern California Edison and presented to the South Coast Air Quality Management District, Los Angeles, California, May 4, 1990.

"An Economist Looks at the Federal Regulation of Biotechnology," presented to the Conference on Emerging Issues in Biotechnology, sponsored by Boston University Law School, Boston, Massachusetts, March 2, 1990.

C. Air Quality

"Economic Impacts of a 65 ppb National Ambient Air Quality Standard for Ozone," Webinar, (with Anne E. Smith), prepared for the Association of Air Pollution Control Agencies, March 2, 2015.

"Cost-Effectiveness of Alternative Wood Stove New Source Performance Standards," (with Andrew Foss), presentation to the U.S. Environmental Protection Agency, Raleigh, NC, February 28, 2013.

"Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations," presented to the U.S. Environmental Protection Agency, November 21, 2011.

"Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations," presented to the U.S. Office of Management and Budget, November 8, 2011.

"Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations," presented to the U.S. Treasury Department, October 26, 2011.

"Potential Impacts of EPA Air, Coal Combustion Residuals, and Cooling Water Regulations," presented to the White House Office of Public Engagement, October 25, 2011.

"Economic Effects of State Restrictions on Interstate Mercury Trading," presented at the Electric Utilities Environmental Conference, Tucson, Arizona, January 22, 2007.

"Using Emissions Trading to Regulate Mercury Emissions in Montana," presented at a Public Hearing, Billings, Montana, June 1, 2006.

"Developing an Emissions Trading Program for Regional Haze," presented to Midwest RPO Regional Air Quality Workshop, Chicago, Illinois, June 28, 2005.

"Developing an Emissions Trading Program for Regional Haze," presented to the Visibility Improvement State and Tribal Association of the Southeast (VISTAS), via conference call from Boston, MA, June 1, 2005.

"Economic and Environmental Analyses of CARB Tier 3 Non-Handheld Exhaust Emission Regulations," presented to the California Air Resources Board staff in Sacramento, CA via videoconference from Boston, Massachusetts, September 18, 2003.

"Market Based Instruments and Shipping Emissions," presented to conference sponsored by DG Environment, Brussels, September 5, 2003.

"Economic and Environmental Analyses of CARB Tier 3 Non-Handheld Emission Regulations: Status Report and Preliminary Results", presented to Outdoor Power Equipment Institute and Engine Manufacturers Association (OPEI & EMA), Washington, DC, August 26, 2003.

"Ex Post Evaluation of the RECLAIM Emissions Trading Program for the Los Angeles Air Basin", presented to OECD Workshop on Ex Post Evaluation of Tradable Permits: Methodological and Policy Issues, Paris, January 21, 2003.

"Emissions and Cost-Effectiveness of the Pull-Ahead Requirements for Heavy Heavy-Duty Diesel Engines," presented to U.S. Office of Management and Budget, Washington, DC, July 24, 2002.

"Economic Analysis of Alternative EPA Snowmobile Regulations," presented to U.S. Environmental Protection Agency Office of Mobile Sources, Ann Arbor, Michigan, May 1, 2002.

"Impacts of ZEV Sales Mandate on California Fleet Emissions," presented to the California Air Resource Board, Sacramento, California, September 7, 2000.

"Economic Assessment of the Cost-Effectiveness of Alternative MACT Standards for the Metal Coil Surface Coating Industry," presentation to the U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 2, 2000.

"Economics and Environmental Regulation: Opportunities and Obstacles," presented to Crowell & Moring, LLP, Washington, DC, March 22, 2000.

"RECLAIM: A Comprehensive Approach to Air Quality Regulation," presented to Edison Electric Institute, Washington, DC, March 6, 2000.

"Economic Assessment of the Cost-Effectiveness of Alternative Phase 2 Regulations for Handheld Engines," presented to the U.S. Environmental Protection Agency and Office of Management and Budget, Washington, DC, February 14, 2000.

"Economic Assessment of the Cost-Effectiveness of Alternative Phase 2 Regulations for Handheld Engines," presented to the U.S. Environmental Protection Agency, Office of Mobile Sources, Washington, DC, October 12, 1999.

"Economic Assessment of the Cost-Effectiveness of Alternative Phase 2 Regulations for Handheld Engines," presented to the U.S. Environmental Protection Agency, Office of Mobile Sources, Ann Arbor, Michigan, October 8, 1999.

"Economic Impacts of ARB Staff Proposed Marine Emission Standards," presented to the California Air Resources Board Hearing, Sacramento, California, December 10, 1998.

"Cost-Benefit Analysis of MACT Standards for Boat Manufacturing," presented to the National Marine Manufacturers Association, Tampa, Florida, October 15, 1998.

"Economic Analyses of Alternative California Standards for Exhaust Emissions from Marine Engines," presented to California Air Resources Board, Sacramento, California, October 9, 1998.

"Tradable Permits for Air Pollution Control: The United States Experience," presented to the Organization for Economic Cooperation and Development Workshop on Domestic Tradable Permit Systems for Environmental Management, Paris, September 24, 1998.

"NO_X Trading Program to Implement EPA's SIP Call," presented to Indiana Department of Environmental Management, Indianapolis, Indiana, May 4, 1998.

"Economic Analysis of Alternative EPA Standards for Large CI Non-Road Engines: Draft NERA Results," presented to the Engine Manufacturers Association and the Equipment Manufacturers Institute, Chicago, Illinois, September 4, 1997.

"Cost-Effectiveness of ARB Small Off-Road Engine Regulations: Preliminary Results," presented to the California Air Resources Board, Sacramento, California, May 2, 1997.

"RECLAIM: Turning Theory Into Practice for Emissions Trading in the Los Angeles Air Basin," presented to the NERA Seminar on Tradable Permits, London, United Kingdom, April 11, 1997.

"RECLAIM: Turning Theory Into Practice for Emissions Trading in the Los Angeles Basin," presented to the *International Workshop on Tradable Permits, Tradable Quotas and Joint Implementation*, University of Sussex, Brighton, United Kingdom, April 9, 1997.

"Economic Analyses of Alternative ARB Regulatory Requirements for Small SI Non-Handheld Engines," presented to the California Air Resources Board staff, El Monte, California, February 4, 1997.

"Cost-Effectiveness of Alternative Emission Control Technologies for Small Utility Engines," presented to California Air Resources Board staff, El Monte, California, December 18, 1996.

"Emission Regulations for Non-Road Engines," presentation to the U.S. Environmental Protection Agency, Ann Arbor, Michigan, July 17, 1996.

"Valuation of Externalities: Methods and Examples," presented to the PSP&ED Advisory Group of the Hawaiian Electric Company, Honolulu, Hawaii, April 3, 1996.

"Valuation of Externalities: Experience and Methods," presented to the Hawaiian Electric Company Externalities Advisory Group, Honolulu, Hawaii, January 31, 1996.

"Emission Regulations for Small Utility Engines," presented to Small Non-Road Engine Regulatory Negotiations, Ann Arbor, Michigan, December 13, 1995.

"Economic Evaluation of Alternative Regulations of Exhaust Emissions from Small Utility Engines," presented to U.S. Environmental Protection Agency, Ann Arbor, Michigan, November 28, 1995.

"Emission Regulations for Small Utility Engines," presented to California Air Resources Board staff, El Monte, California, October 3, 1995.

"Briggs & Stratton/NERA Phase 2 Economic Study," presented to U.S. Environmental Protection Agency, Ann Arbor, Michigan, September 22, 1995.

"RECLAIM: Turning Theory Into Practice for Emissions Trading in the Los Angeles Basin," presented to the Stanford Law School Environmental Markets Seminar, Stanford, California, March 8, 1995.

"Emission Trading for NO_X: Experience with RECLAIM," presented to Edison Electric Institute, Washington, DC, May 26, 1994.

"Emission Trading for NO_X: The RECLAIM Experience," presented to Edison Electric Institute, May 13, 1994.

"Projecting the Price of RECLAIM Trading Credits for NO_X," presented at a California Energy Commission Workshop, Sacramento, California, February 4, 1994.

Comments on "Presumptive Pigouvian Tax: Complementing Regulation to Mimic an Emissions Fee," presented to the Conference on Market Approaches to Environmental Protection, Stanford University, Palo Alto, California, December 3, 1993.

"Economic Effects of Regulatory Requirements to Protect Grand Canyon Visibility," presented to the Grand Canyon Visibility Transport Commission, Salt Lake City, Utah, October 21, 1993.

"Evolving Role of Externalities in Utility Activities," presented to the Electric Power Research Institute Energy Analysis Task Force, Nashville, Tennessee, September 29, 1993.

"External Costs of Electricity Generation in Southern Nevada," presented on behalf of Nevada Power Company, at a workshop sponsored by the Nevada Public Service Commission, Las Vegas, Nevada, May 19, 1993.

"Environmental Externalities," presented to Central and Southwest Corporation, Dallas, Texas, May 4, 1993.

"Creating Markets for Environmental Protection: Overview of Experience with Tradable Permit Systems," presented at The Claremont Institute

Conference *Environmental Protection Through Market Incentives: A Strategy for the Future*, Los Angeles, California, January 20-21, 1993.

"Tradable Permits and Social Costing: The California Experience," presented at the American Economic Association and Allied Social Science Association Meetings, Anaheim, California, January 6, 1993.

"The Distributive Impacts of Economic Instruments for Environmental Policy," presented to the OECD Group on Economic and Environmental Policy Integration, Paris, November 19, 1992.

"Emissions Trading: A Better Way to Incorporate Environmental Costs in Electric Utilities Resource Planning," presented at the Pace University

Center for Environmental Legal Studies Conference on *Incorporation of Social Costs of Energy in Resource Acquisition Decisions*, Racine, Wisconsin, September 8-11, 1992.

"Banking and Trading of Air Emission Reduction Credits," presented to the State of Connecticut Office of Policy and Management Meeting on Emissions Trading, Hartford, Connecticut, July 22, 1992.

"The Distributive Effects of Economic Instruments for Environmental Policy," presented to the OECD Group on Economic and Environmental Coordination, Paris, June 18, 1992.

"A Marketable Permits Program for the Los Angeles Air Basin," prepared for MIT Center for Energy and Environmental Policy Research *1992 New Developments Workshop*, Cambridge, Massachusetts, April 30, 1992.

"The Road From Theory to Practice: Developing a Marketable Permits Program for the Los Angeles Air Basin," seminar presented to the MIT Center for Energy and Environmental Policy Research, Cambridge, Massachusetts, March 11, 1992.

"Southern California Edison Damage-Based Values for Residual Emissions Valuation," presented to the California Energy Commission ER 92 Committee Workshop on Air Emission Damage Functions, Sacramento, California, January 29, 1992.

"Turning Theory Into Practice: Developing a Marketable Permits Program for the Los Angeles Basin," prepared for Project 88 -- Round II Seminar, John F. Kennedy School of Government, Harvard University, Cambridge, Massachusetts, December 11, 1991.

"Workshop on Economic Instruments," prepared for Imperial Oil Ltd., Toronto, Canada, October 1-2, 1991.

"Market-Based Approaches to Air Quality Improvement," presented to the Board of Directors of the California Council for Environmental and Economic Balance, San Diego, California, July 1991.

"Environment and Equity," presented to the Board of Directors of the California Council for Environmental and Economic Balance, San Diego, California, July 1991.

"Contribution of Economists to Environmental Policy: Comments on the Gruenspect-Lave Critical Review," presented to the Air and Waste Management Association, Vancouver, British Columbia, June 19, 1991.

"Airports and Economic Development," presented to the Southeast Chicago Development Commission, Chicago, Illinois, May 24, 1991.

"Environmental Economics in the 1990s," presented to the OECD Group of Economic Experts, Paris, May 16, 1991.

"The Clean Air Act: How to Make the Mandate Worth the Effort," presented to the Workshop on Emerging Environmental Policies and Business, North Carolina State University, Raleigh, North Carolina, April 18, 1991.

"Market-Based Approaches to Managing Air Emissions in California's South Coast Basin," presented to Workshop on Market Incentives, South Coast Air Quality Management District, El Monte, California, January 29, 1991.

"Market-Based Approaches to Managing Air Emissions in California's South Coast Basin," presented to the Steering/Advisory Committee on Market Incentives, South Coast Air Quality Management District, Los Angeles, California, December 11, 1990.

"How Environmental Policies Influence Natural Gas Markets," presented to the Conference on Emerging Competition in California Gas Markets, sponsored by the California Energy Commission, San Diego, California, November 9, 1990.

"Air Quality and Electric Vehicles," presented to the Electric Vehicle Symposium, sponsored by the Western Energy Supply and Transmission Associates, Ontario, California, November 8, 1990.

"Incorporating Environmental Impacts in Public Utility Commission Regulation," presented to the Energy Research Group, Washington, DC, November 6, 1990.

"The Promise and Performance of the Acid Rain Allowance Program," presented to the Conference on the New Acid Rain Legislation: Capitalizing on a Market-Based Approach, sponsored by Public Utilities Reports, Inc., Washington, DC, October 24, 1990.

"What Environmental Legislation Means for Crude Oil Marketers: A U.S. Overview," prepared for the Oxford College of Petroleum Studies, Long Beach, California, presented October 1, 1990.

"Market-Based Approaches for Environmental Improvement," presented to the Eleventh Annual Antitrust and Trade Regulation Seminar, sponsored by National Economic Research Associates, Santa Fe, New Mexico, July 5-7, 1990.

"Using Market-Based Approaches in the Energy Sector," presented to the OECD Economic Incentives Working Group, Paris, June 19-20, 1990.

"Emissions Trading: Concepts and Experience," prepared for The Canadian Electrical Association and presented at the *Workshop on Tradable Permits*, Toronto, Canada, June 13, 1990.

"Prototypical Trading Policy: Stationary Sources of NO_X," prepared for NO_X/VOC Task Force and presented at the *Workshop on Flexible Mechanisms*, Montreal, Canada, June 6-7, 1990.

"Emissions Trading: An Overview of Concepts and Experience," prepared for NO_X/VOC Task Force and presented at the *Workshop on Flexible Mechanisms*, Montreal, Canada, June 6-7, 1990.

"Market-Based Approaches for Environmental Improvement," presented to the Board of Directors, The Conference Board of Canada, Edmonton, Canada, May 30, 1990.

"Market-Based Approaches for Environmental Protection: Lessons from the U.S. Experience," presented to the Advisory Board, Research Program on Business and the Environment, The Conference Board of Canada, Toronto, Canada, April 24, 1990.

"Ozone and Economics," presented to the Air and Waste Management Association, Los Angeles, California, March 20, 1990.

"Clear Thinking on Clear Air: Agenda for the 1990's," paper and panel discussion presented at the American Enterprise Institute's Thirteenth Annual Policy Conference, Washington, DC, December 4, 1989.

"The Acid Rain Allowance Program," presented to the Energy Research Group, Washington, DC, November 3, 1989.

D. Water Quality and Natural Resources

"316(b) Economic Assessments: Lessons Learned Over the Past Two Decades," presented at EPRI Conference on Clean Water Act 316(b): Rule Compliance and Lessons Learned, Atlanta, Georgia, June 11, 2019.

"Benefits Evaluation and Monetization in EPA's §316(b) Final Rule: Economic Issues," presented at EPRI Conference on Technical Challenges for Implementing Clean Water Act §316(b) at Power Plants Withdrawing Cooling Water from Reservoirs, Huntersville, North Carolina, May 18, 2018.

"Social Cost Analysis in Section 316(b) Cost Evaluation Studies," presented to Electric Power Research Institute Section 316(b) Conference on Technical Challenges for Ohio/Tennessee River Basin Power Plants, Columbus, Ohio, March 15, 2017.

"Benefits Evaluation and Monetization in EPA's §316(b) Final Rule: Economic Determinations and Issues," presented at EUCI Conference on 316(b) Final Rule, September 29, 2016.

"Cost-Benefit Assessments for 316(b): Some Implementation Issues," presented at UWAG Webinar on 316(b) Implementation Issues, August 5, 2015.

"Benefit-cost Assessment of Section 316(b) Entrainment Alternatives," presented at the EUCI Conference on 316(b), Providence, Rhode Island, October 8, 2014

"Benefit-Cost Analysis in Section 316(b) BTA Determinations: The Road Ahead," presented at the American Fisheries Society Symposium, Seattle, Washington, September 6, 2011.

"Cost-Benefit Analysis for Fish Impingement and Entrainment Reduction at Pickering Nuclear Generating Station," presented to Canadian Nuclear Safety Commission, Ottawa, Canada, October 29, 2009.

"Cost-Benefit Analysis for Fish Impingement and Entrainment Reduction at Pickering Nuclear Generating Station," presented at Ontario Power Generation Inc. Stakeholder Workshop, Ontario, Canada, September 29, 2009

Uncertainty in §316(b) Compliance Demonstration: Case Study Including Monte Carlo Analysis," presented at the UWAG/EPRI Conference on Technologies and Techniques for §316(b) Compliance, Atlanta, Georgia, September 7, 2006.

"Electricity System Impacts of Nuclear Shutdown Alternatives," presented to New York City Council, New York, NY, May 7, 2002.

"Electricity System Impacts of Nuclear Shutdown Alternatives," presented to Westchester County Board of Legislators Committee on Environment and Health, Westchester, New York, April 29, 2002.

"An Economic Approach to 316(b) BTA Determination," presented to the UWAG 316(b) Technical Workshop for the Environmental Protection Agency, Annapolis, Maryland, January 25, 2001.

"Methodology for Cost-Benefit Assessment of Fish Protection Alternatives for the Mercer Facility," presentation to the Mercer 316(b) Permit Team, Newark, New Jersey, August 8, 2000.

"Roadmap for Costs & Benefits of Fish Protection Alternatives for the Salem Facility," presented to the Monitoring Advisory Committee, Mt. Laurel, New Jersey, December 9, 1999.

"Costs & Benefits of Fish Protection Alternatives at the Salem Generating Facility," presented to the New Jersey Department Environmental Protection, Trenton, New Jersey, May 4, 1999.

"Natural Resource Damage Assessments: Economic Techniques," presented to PSE&G, Newark, New Jersey, December 9, 1997.

"Use of Economic Analysis in Environmental Impact Statements and Other Regulatory Proceedings," presented to Hudson River Utilities, New York, New York, November 19, 1997.

"Combining Science and Economics: The Case of Superfund," presented to ENVIRON, Princeton, New Jersey, May 16, 1995.

"Social Costing: Policy Overview," presented to the British Columbia Utilities Commission Social Costing Workshop, Vancouver, British Columbia, March 29, 1995.

AFFIRMATION

STATE OF Oregon)
) ss.
COUNTY OF Multnomah)

I, DAVID HARRISON, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

DAVID HARRISON

Subscribed and sworn to before me
this 20 day of June, 2019.

Haylee Perkins
NOTARY PUBLIC

OFFICIAL STAMP
HAYLEE ROSE PERKINS
NOTARY PUBLIC-OREGON
COMMISSION NO. 986527
MY COMMISSION EXPIRES APRIL 25, 2023

SHANE PRITCHARD

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Third Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-06___

Prepared Direct Testimony of

Shane Pritchard

I. INTRODUCTION

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

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

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

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

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

A. No, I have not.

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

A. I sponsor the Companies' Renewable Energy Plan, Section 4 of the Third Amendment to the 2018 Joint Integrated Resource Plan ("IRPA"). Specifically, I support the sections relating to the processes followed and results of the Fall 2018 Renewable Energy Request for Proposals ("Fall 2018 Renewable RFP" or "RFP"), including the three power purchase agreements ("PPAs") between Nevada Power and counterparties. I also explain and support the Companies' plan for complying with Nevada's renewable portfolio standard (the "RPS"), which includes changes in the compliance targets effected by Senate Bill 358 ("SB358") of the 80th Session of the Nevada Legislature.

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

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

- **Exhibit Pritchard-Direct-1**, Statement of Qualifications
- **Exhibit Pritchard-Direct-2**, Key Provisions of the New PPAs

6. Q. WHAT MATERIALS ARE YOU SPONSORING?

A. I sponsor the following Technical Appendices:

- REN-1 2019 IRP RE-RFP Top Projects PPA 12x24 Supply Tables

- REN-2 2019 IRP Generic Placeholder 12x24 Supply Tables
- REN-3 2019 IRP Generic Placeholder Pricing (Confidential)
- REN-4 2019 IRP Buildout Scenarios
- REN-5 Fall 2018 RE RFP Protocol
- REN-6-GS (a) Long-term Renewable Power Purchase Agreement with Solar Partners XI LLC
- REN-6-GS (b) Gemini Solar RPS Regulation Roadmap
- REN-6-MS (a) Long-term Renewable Power Purchase Agreement with Arrow Canyon Solar LLC
- REN-6-MS (b) Moapa Solar RPS Regulation Roadmap
- REN-6-SBS (a) Long-term Renewable Power Purchase Agreement with 300MS 8ME LLC
- REN-6-SBS (b) Southern Bighorn Solar RPS Regulation Roadmap
- REN-7 - RFP Final Shortlist Scoring Report (Confidential)
- REN-8 – Final Due Diligence and Selection Reports (Confidential)
- REN-9 – Fall 2018 RE RFP Report of the Independent Evaluator (Confidential)

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

A. Yes. Technical Appendices REN-3, REN-7, REN-8, and REN-9 are confidential. REN-3 contains forecasted pricing for renewable projects. This information must remain confidential in order to provide the Companies with the best opportunity to transact in the marketplace on behalf of their customers. REN-7, REN-8, and REN-9 contain the results of the Companies' and the Independent Evaluator's ("IE's") evaluation of the projects from the initial bidder short list coming out of the Fall 2018 Renewable RFP, including pricing and scoring results for each of the bids submitted. This information was provided to the Companies by bidders under a commitment, expressed through the Fall 2018 Renewable RFP, to not share confidential bidder information with competitors. In addition, this information contains the due diligence reports from subject matter experts evaluating projects that bid into the Fall 2018 Renewable RFP. Confidentiality of the Companies' economic and technical evaluations of bids is essential to a successful competitive solicitation.

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

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

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

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

II. PLANNING TO COMPLY WITH NEVADA'S RENEWABLE PORTFOLIO STANDARD ("RPS")

10. Q. PLEASE DESCRIBE THE RPS.

A. Nevada utilizes a portfolio energy credit ("PC") system to enforce the RPS. Eligible PCs can come from multiple sources beyond just net generation in the current year. The renewable energy planning section of this IRP amendment is based on the changes to the RPS that were effected by SB358.

Nevada's RPS requirement is currently set at 20 percent of retail sales. This means that Nevada Power and Sierra provide renewable energy credits equal to 20 percent of their retail sales. Under SB358, the RPS will increase to 22 percent in 2020, 24 percent in 2021, 29 percent in 2022, 34 percent in 2024, 42 percent in 2027, and 50 percent in 2030 and each calendar year thereafter. SB358 also establishes 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 in this State."[1]

The law kept in place a limited allowance for credits from energy efficiency and conversation measures that can be used to meet the RPS; the elimination of the solar multiplier for solar projects placed into operation on January 1, 2016 or later and the elimination of station usage for projects placed into operation on or after January 1, 2016, (except in the case of the geothermal facilities, where the station service energy is used for the extraction, transportation, pumping or compressing of geothermal brine). Consistent with the aspirational goal regarding zero carbon dioxide emission resources, SB358 includes a provision pursuant to which electricity produced by Hoover Dam will produce PCs. Finally, sales made to customers pursuant to optional green energy pricing programs where the Companies either retire PCs on behalf of the customer or transfer PCs to the customer are excluded from the definition of "retail sales."

[1] Senate Bill 358 § 8(2).

11. Q. PLEASE DESCRIBE GENERALLY THE RPS RENEWABLE PLAN DEVELOPED FOR THE IRP.

A. The Companies use a model to forecast future PC requirements and PC supplies. The purpose of the model is to determine whether the Companies will have a sufficient number of PCs to meet their RPS obligations. If, outside the Action Plan period, the model indicates that the PC supply is insufficient to meet the RPS, generic placeholder projects are added, as needed, to fill the credit gaps. A supply table for the generic renewable placeholder project is set forth in **Technical Appendix REN-2**. Pricing for the generic renewable placeholder is set forth in **Confidential Technical Appendix REN-3**.

Key inputs to the model include a list of current operating renewable resources, all approved renewable resources under development or construction, and all other sources of eligible credits. The model incorporates all statutory and regulatory limitations, as well as non-RPS portfolio credit obligations, in order to calculate the total number of eligible credits available to meet the RPS for each planning year. This total is then compared against the forecast credit requirement to determine whether each Company will have a sufficient number of credits to meet its RPS obligation. Below are the key assumptions that are incorporated into the model:

- Full compliance with an escalating and compressed RPS schedule: 22 percent by 2020, 24 percent by 2021, 29 percent by 2022, 34 percent by 2024, 42 percent by 2027, and 50 percent by 2030;

- Existing contracts expire in accordance with the contract terms and are not automatically renewed;

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- The Companies adjust the expected amount of energy and credits from renewable facilities for the period of 2019-2022 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 its annual ESPs. This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-term plans;

- The Renewable Generations incentive programs will continue until funds are exhausted and/or the programs expire in 2021, and solar systems placed into service after 2015 do not qualify for the solar multiplier. The plan assumes that the number of credits for Renewable Generations will plateau in 2020 and then remain flat;

- The plan assumes that the percent of annual credit contribution from energy efficiency and conservation measures would be limited to no more than 20 percent of the credit total in 2019, decreasing to no more than 10 percent of the total in 2020, and finally 0 percent of the total starting in 2025;

- Surplus credits are carried forward without limitation;

- The forecast contemplates that, in addition to existing, approved energy credit sales to customers pursuant to the NV GreenEnergy Rider ("NGR") tariff, the Companies will sell 107,000 kPCs to customers such as the proposed transaction with the Truckee Meadows Community College;[2]

- The plan contemplates that Nevada Power will continue to repay its credit obligation to Sierra, with all credits fully repaid by 2021 (which is before Sierra would have a need to add a new project);[3]

[2] As noted in the testimony of John (Jack) P. McGinley, the Companies are discussing transactions with existing and potential large commercial and industrial customers and potential customers. The transactions are designed to meet the customer's individual needs. To the extent these transactions involve the sale or transfer of portfolio energy credits, the potential transactions are "accounted" for in the RPS compliance forecast if the sale does not exceed 107,000 kPCs annual. To the extent these transactions are not accounted for in the RPS compliance forecast, subsequent filings will analyze the impact of the transaction on RPS compliance.

[3] The repayment over a three year period is a modeling protocol in the renewable planning process but is not intended to reflect how and when actual repayments would be made since such amounts would be dependent on the factual circumstances that will occur during this time period (*e.g.*, load, renewable generation, changes in law, etc.).

- The plan assumes that generation from both Company-owned photovoltaic systems and PPA projects will begin degrading the year following the first full year of operation;

- Geothermal projects and placeholders would continue to qualify for station usage credits; all other technologies would no longer qualify;

- The plan accounts for all Commission-approved NGR agreements as of April 2019 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 tariff, and therefore cannot be used by the Companies in meeting their RPS credit requirements;

- The plan assumes the ability to exclude NGR sales from total retail sales in the RPS calculation;

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

- The plan assumes no further changes to the existing statutory and regulatory regime beyond those enacted under SB 358; and

- The preferred plan assumes the approval of the three new PPAs with the energy and credits to be divided between the two utilities as follows: 200 MW Moapa Solar ("Moapa"), 30 percent to Nevada Power and 70 percent to Sierra; 300 MW Southern Bighorn Solar ("SBS"), 60 percent to Nevada Power and 40 percent Sierra; and 690 MW Gemini Solar ("Gemini"), 100 percent to Nevada Power, even though all three PPAs are contracted through Nevada Power.

12. Q. PLEASE EXPLAIN THE ASSUMPTIONS AND METHODOLOGY UNDERLYING THE NEAR TERM ADJUSTMENTS MADE TO THE RENEWABLE EXPANSION PLAN.

A. The Companies have attempted to capture and reflect actual historical generation trends of the current renewable fleet based on two or more years of operating data. The Companies adjusted the supply tables based on this historical trend to reflect the most recent operating data after coordinating with internal contract owners to account for potential short-term anomalies. Historical output trends for renewable projects under contract with Sierra resulted in a decrease in the amount of expected energy and PCs for eleven projects and an increase for one project. In total, these adjustments lowered the amount of projected energy and PCs by an average of 2.97 percent over the 2020-2022 planning period.

The same approach for Nevada Power resulted in adjustments to the amount of energy and PCs for eight projects, with increases (two projects) and decreases (six projects). In total, these adjustments lowered the amount of renewable energy by an average of 1.12 percent over the 2020-2022 planning period. The majority of this decrease is driven by the downward adjustment from Crescent Dunes, as discussed below. This approach is more accurate and increases the reliability of the overall energy supply used in long-term planning.

13. Q. PLEASE DESCRIBE NEVADA POWER'S RPS OUTLOOK FOR THE ACTION PLAN PERIOD.

A. Nevada Power complied with the 2018 RPS requirement of 20 percent as well as the 2018 solar RPS requirement of six percent, ending 2018 with an overall RPS compliance result of 24.4 percent, 50.5 percent from solar generation. Nevada Power is currently positioned to meet its 2019 and 2020 RPS obligations and, although in 2021 it expects to comply with the RPS, 2021 compliance is not without its risks. The most significant risk is associated with the performance of the Crescent Dunes solar facility. Crescent Dunes is a large, 110 megawatt ("MW"), solar thermal generator that was expected to deliver in excess of 500,000 kPCs (thousand PCs) annually. Since declaring commercial operation in 2015, it has experienced frequent and prolonged outages. The current outlook, based on 2018 production, assumed that Crescent Dunes would produce approximately 250,000 kPCs in 2019 and approximately 375,000 kPCs beginning in 2020 and every year thereafter.

The compliance forecast (which was used for the purpose of preparing this filing) was completed in March 2019. In April 2019, Crescent Dunes experienced another equipment failure and was taken out of service. There is significant uncertainty associated with Crescent Dunes.

Although the forecasting model indicates that Nevada Power should have sufficient PCs to meet both the RPS and its other credit obligations though 2027, this forecast is not 100 percent certain for multiple reasons. First, the outlook assumes that Crescent Dunes is able to permanently resolve all operating issues, which at this time is a significant unknown. Next, another renewable resource could develop issues resulting in lost credits that could accumulate to a point where they must be replenished. Finally, there is the risk that one or more of the six PPAs approved in Docket No. 18-06003 (“2018 IRP”) will be delayed or cancelled. In order to meet the higher credit requirement, all of the projects approved in the 2018 IRP must achieve their operating date targets as any credits lost due to delays cannot be easily or quickly replaced.

14. Q. PLEASE DESCRIBE SIERRA’S RPS OUTLOOK FOR THE ACTION PLAN PERIOD.

A. Sierra complied with the 2018 RPS requirement of 20 percent as well as the 2018 solar RPS requirement of six percent, ending 2018 with an RPS compliance result of 24.7 percent overall and 33.2 percent from solar generation.

Sierra's outlook is cautious. Unlike Nevada Power, which currently only has a very small number of NGR[4] customers, the ability of Sierra to exclude NGR sales from the RPS calculation under the new RPS rules will effectively reduce its overall credit requirement by over 240,000 kPCs. This adjustment provides Sierra just enough cushion to absorb a 2021-increase in the RPS to 29 percent until which time the 1,001 MWs of new solar generation approved in 2018 IRP is expected to become operational. Like Nevada Power, the increases in RPS targets per SB358 will require Sierra to add new resources. With economic growth in the north, Sierra could face unanticipated load increases, one or more of the six projects recently approved by the Commission could be delayed or cancelled, and, finally, one or more of its current operating projects could begin to fall short of its supply commitment or be terminated early. The current RPS planning model indicates that, even if projects in development commence operations as planned and all projects perform as expected (i.e. "best case"), Sierra will still fall short on the number of credits needed to meet the RPS starting in 2024.

15. Q. WHAT WOULD THE COMPANIES PROPOSE IF RPS RISKS AND FUTURE COMPLIANCE WERE THE ONLY RATIONALE FOR SEEKING THE APPROVAL OF NEW PROJECTS?

A. The Companies would seek approval of SBS and Moapa projects, the top two projects in the Fall 2018 Renewable RFP, as Sierra has a near-term credit need with the recent increases to the RPS. Even assuming no issues with its existing portfolio of projects, and that there are no delays with any of the six recently approved PPAs, Sierra would still need to add approximately 350 MW of new

[4] "NGR" refers to NV GreenEnergy Rider Schedule No. NGR approved in Docket No. 14-06031.

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renewable generation in the 2024 to 2026 timeframe or face non-compliance.[5] Furthermore, while the RPS model indicates that Nevada Power should not need to add new resources until 2028, this outlook is based on the assumptions that Crescent Dunes is able to achieve 75 percent of the supply commitment, and that all of the PPAs approved in the 2018 IRP filing fully meet operating dates and supply commitments.[6] This is why it is prudent to procure renewable resources beyond the minimum level needed, if those resources can be procured under favorable terms and the generation is needed, so that neither utility is placed in a situation where it must find an alternative source of credits in a short time frame.

To be clear, if RPS compliance were the only issue, the renewable expansion plan would only include the Moapa and SBS projects discussed below. As Mr. McGinley explains in more detail, several different interests – for example, the opportunity to reduce the open position cost-effective long-term obligations, the goal of showing customers that the Companies are committed to carbon reductions, and the need to develop optional programs that meet the needs of existing and potential large commercial and industrial customers – animate or drive the formulation of the Preferred Plan. In a more simplistic, binary decision making process, the 690-MW Gemini project can be seen as advancing interests other than complying with Nevada's RPS (even though a side benefit is that the project greatly assists the Companies in complying with future increases in the RPS).

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[5] The 350 MW assumes solar PV. See Technical Appendix REN-4 table "Base Retail Sales, All Placeholder Buildout SPPC".

[6] Crescent Dunes experienced an equipment failure in early April requiring that the plant be taken out of service. This incident occurred after the models were created. Model assumptions may need to be revised depending upon how long the plant remains out of service.

16. Q. HOW DO THE COMPANIES INTEND TO ADDRESS RPS RISKS AND FUTURE COMPLIANCE?

A. Nevada Power is seeking Commission approval for three new 25-year PPAs for a combined total of approximately 1,190 MW of new renewable resources to expand the Companies' renewable energy portfolio, support optional pricing programs for new and existing customers and to help ensure continued compliance with an increasing RPS. Project energy, kPCs, and costs are to be apportioned between the Companies as shown below in Table-1.[7] This additional generation will help ensure continued ability to comply with the new and much higher RPS.

TABLE-1

NEW CONTRACTS

Counterparty	Nevada Power Share	Sierra Share	Capacity	Expected Commercial Operation
8minutenergy Southern Bighorn Solar	60 percent	40 percent	300 MW 135 MW Battery Storage	09/01/2023
EDF Renewables Moapa Solar	30 percent	70 percent	200 MW 75 MW Battery Storage	12/1/2022
Arevia Gemini Solar	100 percent		690 MW 380 MW Battery Storage	12/1/2023

[7] Project energy, kPCs, and costs are to be apportioned between the Companies as follows: 200 MW Moapa, 30 percent to Nevada Power and 70 percent to Sierra; 300 MW SBS, 60 percent to Nevada Power and 40 percent Sierra; and 690 MW Gemini, 100 percent to Nevada Power.

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III. THE FALL 2018 RENEWABLE RFP AND THE THREE NEW RENEWABLE PPAS THAT RESULTED

17. Q. HOW HAVE YOU ORGANIZED THIS PORTION OF YOUR TESTIMONY?

A. Beginning in Section III, the narrative provides a detailed description of the Fall 2018 Renewable RFP process, beginning with the development of protocols for the Fall 2018 Renewable RFP through selection of the final proposals for negotiation. My testimony will cover the following:

1. The reason for issuing the Fall 2018 Renewable RFP;
2. The Fall 2018 Renewable RFP Bid Protocol;
3. The issuance of Fall 2018 Renewable RFP and bids received;
4. The initial evaluation process and selection of the initial short list;
5. The additional analysis of the shortlisted bids, and the final selection; and
6. The three new renewable PPAs.

18. Q. WHY WAS THE FALL 2018 RENEWABLE RFP ORIGINALLY ISSUED?

A. The Fall 2018 Renewable RFP was issued to continue the expansion of the Companies' supply-side and renewable energy portfolios, to support optional pricing programs for customers, and to support an increase in the RPS, to capture renewable pricing that qualifies for the full 30 percent Federal Investment Tax Credit ("ITC") for the economic benefit of customers, and to continue the Companies' drive towards 100 percent renewables.

19. Q. PLEASE DESCRIBE THE FALL 2018 RENEWABLE RFP PROTOCOL.

A. The Companies prepared a complete bid package ("Protocol") describing the purpose of the Fall 2018 Renewable RFP, the process by which it would be conducted, the schedule, a description of the information required for each bid,

bid submittal instructions and minimum eligibility requirements. The Protocol also included a description of the evaluation process that would be used to select winning bidders. The Protocol included pro-forma agreements for bidders to review and comment on. The Protocol is set forth in **Technical Appendix REN-5**.

20. Q. PLEASE DESCRIBE THE FALL 2018 RENEWABLE RFP PROCESS.

A. The Fall 2018 Renewable RFP was issued on October 16, 2018. The Companies requested proposals for projects that qualified as renewable energy resources under Nevada Revised Statutes ("NRS") § 704.7811, including, but not limited to, solar, geothermal, wind, and biomass. Additionally, the Protocol included a solicitation for supplemental battery energy storage systems ("Battery Storage") eligible for the ITC. The Companies solicited renewable energy resources with all associated environmental and renewable energy attributes. The Companies requested a commercial operation date on or before December 31, 2023. Projects were required to be integrated into the Companies' transmission system as a network resource, to be located in the Companies' service territories, and to be capable of delivering energy to serve the Companies' retail loads.

Bids were received on December 17, 2018. The Companies received nearly 150 conforming bids from 18 counterparties, totaling more than 5,500 MW and 2,800 MW of supplemental Battery Storage. Responses included six bids for a geothermal product, one bid for a concentrated solar power product, and one bid for a biomass power product. The balance of conforming bids were for solar PV products.

21. Q. PLEASE DESCRIBE THE INITIAL EVALUATION PHASE.

A. In the initial evaluation phase, bids were ranked based on a combination of three criteria: price, non-price, and economic benefits to the State of Nevada.

Price was measured by calculating the levelized cost of energy ("LCOE") over the term of the proposed PPA or build transfer agreement. The LCOE included projected energy payments under the agreement and the estimated cost of network upgrades for the proposed project. The LCOE accounted for any proposed escalation of the bid price, as well as any degradation in energy deliveries over the term of the PPA (or life of project), as indicated by the bidder in their bid submittal. The price score was given a 60 percent weight.

The non-price scoring was based on four categories: (1) the bidder's project development experience, (2) the technology of the project, (3) conformity to the pro-forma PPA, and (4) project development milestones. The technology review included scoring for: (1) flexibility, (2) environmental benefits, (3) fuel diversity and hedging, (4) other ancillary services, (5) technical feasibility, (6) resource quality, (7) equipment supply control, and (8) utilization of resource. The non-price score was given a 30 percent weight.

The economic benefit scoring was based on three categories: (1) location of jobs created, (2) number of jobs created, and (3) economic benefits to Nevada. The economic benefits score was given a 10 percent weight.

Based on the resulting weighted scores of the bids, an initial short list was developed. Bidders selected for the Fall 2018 Renewable RFP initial short list were notified of their status on February 5, 2019. Shortlisted bidders were permitted to submit a "best and final" proposal by February 8, 2019. Bidders not selected for the initial short list were also notified of their status on February 5, 2019. One bidder was later added to the initial short-list on March 9, 2018, with their best and final proposal due on March 13, 2018. The final short list and scoring for all of the submitted bids is included in **Confidential Technical Appendix Item REN-7**.

22. Q. PLEASE DESCRIBE ANY ADDITIONAL ANALYSIS CONDUCTED ON THE SHORTLISTED BIDS.

A. The Resource Planning group conducted a present worth revenue requirement ("PWRR") analysis of shortlisted bids using PROMOD, the production cost model. The PWRR analysis is described in the economic analysis narrative section of this filing.

Additional due diligence was conducted on the initially shortlisted bids. The due diligence included: (1) status and timing of interconnection, (2) site control, (3) status of material permits, (4) solar panels, (5) other material equipment, (6) delivery profile, (7) milestone schedule, (8) material exceptions to the pro-forma agreement, (9) development and operating experience, (10) financial capability, (11) safety, (12) water supply, and (13) project labor agreement. Burns & McDonnell was retained to evaluate items (4), (5), (6), (7), and (9) and internal subject matter experts evaluated the remaining items.[8] Based on this analysis, the top bidders for negotiations were selected. No material concerns were raised with the shortlisted bids at that time. The Companies' final due diligence reports for

[8] Burns & McDonnell possesses analysis tools and expertise to validate bidder-provided energy production forecasts that the Companies do not. Additionally, they monitor the renewable equipment and construction markets and are therefore positioned to provide recommendations regarding technology and developers.

the shortlisted 2018 Renewable RFP bids are included in **Confidential Technical Appendix Item REN-8**.

An IE was engaged to oversee the Fall 2018 Renewable RFP process. The IE monitored RFP activities to ensure that a competitive, fair, and transparent RFP process was conducted. Among other tasks, the IE validated that the Fall 2018 Renewable RFP evaluation criteria, methods, models, and other processes were consistently and appropriately applied to all bids and bidders, and that the assumptions, inputs, outputs, and results were appropriate and reasonable. The IE independently scored all bids to determine whether the Companies' initial and final selections were reasonable. The IE also monitored negotiations. The IE's report is provided in **Confidential Technical Appendix REN-9.**

The Companies successfully completed PPA negotiations with 8minutenergy ("8ME"), EDF Renewables ("EDFR"), and Arevia Power ("Arevia"). Each project is described in more detail below.

23. Q. PLEASE DESCRIBE 8ME's SBS PROJECT.

A. Nevada Power and developer 8ME have executed a PPA for the output of 300 MW with a 135 MW Battery Storage system from the SBS project. SBS will be located on approximately 2,600 acres of land leased from the Moapa River Band of Indians, northeast of Las Vegas, Nevada.

The SBS project is expected to utilize some 892,304 mono-crystalline solar photovoltaic panels, each rated at approximately 400 watts, to generate approximately 1,034,831 megawatt-hours ("MWh") of electricity in the first full year of production. 8ME projects that the energy supply amount will degrade at approximately 0.3 percent per year. Nevada Power has agreed to purchase the solar output of the SBS facility for 25 years from January 1 immediately following the expected commercial operation date of September 1, 2023. The fixed price of the contract for the solar output is $22.32 per MWh except for hours ending 1700 through 2100 in June, July, and August when the price is $145.08 per MWh. These prices are flat for the term of the contract and include all costs associated with the collocated 135 MW/540 MWh Battery Storage system. The LCOE of the SBS PPA is $36.86 per MWh including the Battery Storage system and $3,670,000 in Nevada Power-funded transmission network upgrade investments necessary to interconnect the project to the transmission system. The PPA provides Nevada Power rights to economically dispatch the facility. Though this PPA is executed by Nevada Power, it is proposed that the costs, energy, and associated PCs be split 60 percent to Nevada Power and 40 percent to Sierra. In addition to the low cost energy and capacity, both Companies' customers will benefit from all associated environmental and renewable energy attributes as the SBS project will help displace fossil-fueled generation.

The project, if approved, is expected to be operational in the third quarter of 2023. The project will consist of monocrystalline high-efficiency photovoltaic panels mounted on horizontal single-axis trackers. The Battery Storage system uses Lithium-ion technology. SBS will interconnect at the 230-kilovolt ("kV") Reid Gardner substation. The PPA between Nevada Power and 300MS 8ME LLC for the SBS project is included as **Technical Appendix Item REN-6-SBS (a)**.

24. Q. PLEASE DESCRIBE THE EDFR MOAPA SOLAR PROJECT.

A. Nevada Power and developer EDFR have executed a PPA for the output of 200 MW with a 75 MW Battery Storage system from the Moapa project. Moapa will provide customers with a low-cost, long-term supply-side resource that provides an element of price predictability and stability.

EDFR has executed an option agreement to lease land on the Moapa River Indian Reservation, approximately 20 miles north of Las Vegas, Nevada, upon which it proposes to build a 200 MW solar PV project with a 75 MW Battery Storage system collocated on the same project site.

The Moapa project is expected to utilize 629,590 415-watt crystalline solar photovoltaic panels to generate approximately 702,186 MWh of electricity in the first full year of production. EDF projects that the energy supply amount will degrade at approximately 0.3 percent per year. Nevada Power has agreed to purchase the solar output of the Moapa facility for 25 years from January 1 immediately following the expected commercial operation date of December 1, 2022. The fixed price of the contract for the solar output is $21.26 per MWh except for hours ending 1700 through 2100 in June, July, and August when the price is $138.19 per MWh. These prices are flat for the term of the contract and include all costs associated with the collocated 200 MW/375 MWh Battery Storage system. Network upgrades estimated to cost $1,300,000 are needed to interconnect the project to the transmission system. The LCOE of the Moapa PPA is $36.79 per MWh for energy including Battery Storage and network upgrades. The PPA provides Nevada Power rights to economically dispatch the facility. Though this PPA is executed by Nevada Power, it is proposed that the costs, energy, and associated PCs be split 30 percent to Nevada Power and 70 percent to Sierra. Moreover, in addition to the low cost energy and capacity, the customers of both Companies will benefit from all associated environmental and

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d/b/a NV Energy

renewable energy attributes as the Moapa project will help displace fossil-fueled generation.

The project is in an advanced stage of development and, if approved, is expected to be operational in the fourth quarter of 2022. The project's monocrystalline high-efficiency photovoltaic panels will be mounted on horizontal single-axis trackers. The Battery Storage system uses Lithium-ion technology. Moapa will interconnect to the 230 kV Crystal substation. The PPA between Nevada Power and Arrow Canyon Solar, LLC for the Moapa project is included as **Technical Appendix Item REN-6-MS (a)**.

25. Q. PLEASE DESCRIBE AREVIA'S GEMINI PROJECT.

A. Nevada Power and developer Arevia have executed a PPA for the output of 690 MW solar PV and 380 MW Battery Storage system from the Gemini project.

Arevia's Gemini project is sited entirely on land administered by the Bureau of Land Management ("BLM") along the south side of Interstate 15 approximately 25 miles north of Las Vegas, Nevada.

The Gemini project is expected to utilize 2,620,804 370-watt bi-facial mono-crystalline solar photovoltaic panels to generate approximately 2,200,000 MWh of electricity in the first full year of production. Arevia projects that the energy supply amount will degrade at approximately 0.5 percent per year. Nevada Power has agreed to purchase the solar output of the Gemini facility for 25 years from January 1 immediately following the expected commercial operation date of December 1, 2023. The fixed price of the contract for the solar output is $24.79 per MWh except for hours ending 1700 through 2100 in June, July, and August when the price is $161.14 per MWh. These prices are flat for the term of the contract and include all costs associated with the collocated 380 MW/1,416 MWh Battery Storage system. Network upgrades estimated to cost $15,630,000 are needed to interconnect the project to the transmission system. The LCOE of the Gemini PPA is $42.83 per MWh for energy including Battery Storage and network upgrades. The PPA provides Nevada Power rights to economically dispatch the facility. It is proposed that the costs, energy and associated PCs be dedicated 100 percent to Nevada Power. Moreover, in addition to the low cost energy and capacity, Nevada Power customers will benefit from all associated environmental and renewable energy attributes as Gemini will help displace fossil-fueled generation.

The project, if approved, is expected to be operational in the fourth quarter of 2023. The project's monocrystalline high-efficiency photovoltaic panels will be mounted on horizontal single-axis trackers. The Battery Storage system uses Lithium-ion technology. Gemini will interconnect at the Crystal substation. The PPA between Nevada Power and Solar Partners XI, LLC for the Gemini project is included as **Technical Appendix Item REN-6-GS (a)**.

26. Q. WHAT KEY PROVISIONS HAVE THE COMPANIES NEGOTIATED WITH THE THREE COUNTERPARTIES AS A RESULT OF THE RFP?

A. Exhibit Pritchard-Direct-2 provides a table detailing the key provisions of the Solar PPAs.

27. Q. WILL THE NEVADA ECONOMY BENEFIT FROM APPROVAL OF THE FALL 2018 RENEWABLE RFP PPAs?

A. Yes, the Nevada economy will benefit from the approval of the Fall 2018 Renewable RFP PPAs. These three PPAs are expected to produce a temporary increase in employment during the construction phase of the projects. Moreover, the construction work will be completed pursuant to work site agreements with the International Brotherhood of Electric Workers Local 396 and 357. In addition to the construction jobs and associated positive economic impacts, the facilities will provide a permanent, long-term increase in employment with the addition of up to 29 positions with a total payroll of $75 million over 25 years.[9] The local and state economies will benefit from the influx of jobs, tax base, and business generated by these projects. The Supply Side Narrative sets forth a complete listing of the economic and environmental benefits of each project, as required by the Commission's regulations.[10]

28. Q. WHY ARE THE COMPANIES RECOMMENDING COMMISSION APPROVAL OF THE DISPATCHABLE SOLAR FACILITIES WITH INTEGRATED STORAGE?

A. Mr. McGinley provides policy testimony supporting the selection of the Preferred Plan. As he explains, the Companies intend to continue the expansion of their supply-side and renewable energy portfolios in order to bring lower costs to customers, support optional pricing programs customers find attractive, to ensure compliance with an increased RPS, and to progress towards the 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

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9 Aggregated figures from the three PPAs.

10 *See*, NAC § 704.8887(2)(c).

electric service in this State."[11] Additionally, as the penetration of renewable energy resources increases, the availability of flexible, near-instantaneous, dependable capacity becomes more important to provide for the safe, stable, and reliable operation of the bulk electric system. The dispatch rights coupled with the integrated storage of these three projects provide capabilities that will help manage system needs when solar generation is high and system demand is low while displacing fossil-fueled generation. These facilities can capture the rising mid-morning solar energy that happens to correlate with low demand on the Companies' system and save that energy for late afternoon and early evening use when system demand is high and solar generation is declining. Alternately, the facilities provide operational flexibility permitting the Companies to dispatch them much like a conventional generating station to optimize overall system needs. Collocated storage facilities provide the Companies' balancing and reliability operators with a variety of on-demand capacity options to support renewable resource intermittency in the locations where they are most critical. Collocated storage facilities consist of a collection of Lithium-ion batteries which may be deployed either fully and nearly instantaneously, or at an extremely accurate and measured rate over the course of several hours. Their availability as an on-demand capacity resource will allow the Companies' balancing authority operators to coordinate with the Companies' resource optimization personnel to ensure the complex interplay between renewable resource intermittency and peak load demand is managed in a safe and reliable manner, lowering stress on the other generating resources as well as Nevada's interties. Finally, because the Lithium-ion batteries are charged by the solar facilities they are collocated near,

[11] Senate Bill 358 § 8(2).

they qualify for ITC monetization and therefore are a lower cost resource than if they were charged from the electric grid.

29. Q. PLEASE EXPLAIN THE COMPANIES' REQUESTS TO APPROVE THE THREE NEW RENEWABLE PPAS, INCLUDING BATTERY STORAGE.

A. Nevada Power proposes that the Commission approve 1,190 MW of new PPAs between Nevada Power and the following three renewable energy project developers:

1) EDFR's Moapa project under Arrow Canyon Solar, LLC for a 200 MW (ac) solar PV facility, with an associated 75 MW Battery Storage system, with an expected Commercial Operation Date of December 1, 2022.
2) 8ME's SBS project under 300MS 8ME, LLC for a 300 MW (ac) solar PV facility, with an associated 135 MW Battery Storage system, with an expected Commercial Operation Date of September 1, 2023.
3) Arevia's Gemini project under Solar Partners XI, LLC for a 690 MW (ac) solar PV facility, with an associated 380 MW Battery Storage system, with an expected Commercial Operation Date of December 1, 2023.

These three PPAs fill identified customer needs at historically low pricing, and fulfill the Fall 2018 Renewable RFP procedural goal. They were selected through a competitive process that was fair and transparent. Although not required, the Companies have selected proposals that meet the criteria of NRS § 704.7316(2)(b)(4); that is, provide the greatest economic benefit to this State, the greatest opportunity for the creation of new jobs in this State, and the best value to customers of the electric utility.

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

A. Yes, it does.

SHANE E. PRITCHARD
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Las Vegas, NV89122

702-439-3545
spritchard@nvenergy.com

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

NV Energy:

2018-Present: Director, Renewable Energy and Origination

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

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

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

2014-2015: Operations Manager for Silverhawk Station

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

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

Other experience:

2000 – 2005: Alstom Power - Field Service Engineer

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

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

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

US Navy:

1991 – 1996: US Navy Nuclear Power

Test Director: USS Abraham Lincoln dry-dock overhaul

- Planned, scheduled and executed complex nuclear reactor plant tests
- Managed shipyard and Navy efforts to repair and upgrade reactor plant systems
- Assisted civilian electrical engineers in E&IC system troubleshooting

Reactor Electrical Division Officer: USS Abraham Lincoln at sea

- Led and trained 30 electricians to operate and maintain propulsion plant electrical systems
- Operated nuclear power plants and maintained associated reactor electrical systems
- Aircraft carrier operations Officer of the Deck (OOD)

EXHIBIT PRITCHARD-DIRECT-2

KEY PROVISIONS OF THE ARROW CANYON SOLAR, LLC[1] PPA

PROVISION	MOAPA SOLAR PPA
Supplier	Arrow Canyon Solar, LLC
Buyer	Nevada Power Company, dba NV Energy
Term	25 years
Net Capacity	200 MW
Battery Capacity	75 MW; 375 MWh over 5-hour duration
Expected Commercial Operation	December 1, 2022
Product Description	Solar photovoltaic with integrated battery storage. Buyer has rights to schedule and dispatch the Generating Facility during the Dispatchable Period. During the Full Requirements Period (hour ending 1700-2100 for June, July and August) Supplier controls the Generating Facility to maximize output.
Yearly PC Amount (Contract Year 1)	639,626 kPCs
Maximum Amount (Contract Year 1)	200 MWh in any hour.
Degradation	Annual Supply Amount, hourly Supply Amounts, Yearly PC Amount and Maximum Amount each decline by 0.3% per year.
Pricing	
Product Rate	$21.26 per MWh during Dispatchable Period; $138.19 per MWh during the Full Requirements Period; no escalation.
Excess Energy Rate	Fifty percent of the Product Rate.
Excess Energy	Delivered amounts above 100% of the Maximum Amount for Contract Year, adjusted for Un-Dispatched Amount.
Test Product Rate	50% of Product Rate.
Provisional Rate	75% of Product Rate.
Provisional Energy	Net Energy (but not Test Energy) that is delivered by Supplier to Buyer prior to the Commercial Operation Date and at the request of Buyer in increments of no less than five (5) MW up to an aggregate maximum of two hundred (200) MW.
Maximum Amount	No payment for amounts delivered above the Maximum Amount in any hour.
Energy Delivery Requirements	

[1] An EDF Renewables subsidiary.

Measurement Periods	Full Requirements Period: hour ending 1700-2100 for June, July and August; Dispatchable Period which is all times that are not Full Requirements Period.
Performance Factor (Shortfall Threshold)	Full Requirements Period Capacity Shortfall: 5% of Full Requirements Period Product, adjusted for Excused Product Dispatchable Period Shortfall: 5% of Delivered Amounts, adjusted for Excused Product.
Shortfall	Full Requirements Period: Amount of undelivered energy below the 95% performance factor. Dispatchable Period: (i) Shortfall: if the Delivered Amounts are less than 95% of the Resource Adjusted Backcast Amount; and (ii) DAR: Dispatchable Accuracy Rate is less than 97% for 3 consecutive months and successive months thereafter. Storage Capacity: Storage Capacity is less than or equal to 90% of the Storage Contract Capacity for two consecutive Contract Years.
Shortfall Consequences	Full Requirements Period: (i) positive difference, if any, between the average Mead Index price during On-Peak hours of the Full Requirements Period and the Full Requirements Period Product Rate times the shortfall amount; (ii) if a Full Requirements Period Capacity Shortfall occurs for second consecutive year the amount of such shortfall times the Full Requirements Period Product Rate shall be deducted from the amounts due Supplier; (iii) if a third consecutive Full Requirements Period Shortfall occurs Supplier shall pay the amounts in (ii) above and Buyer shall have the right to terminate the agreement. Dispatchable Period: (i) Shortfall: positive difference, if any, between the average Mead Index price during the On-Peak hours of the Dispatchable Period and the Product Rate times the shortfall amount. (ii) DAR: after three months to six months buyer only pays for Delivered Energy not the Un-Dispatched Amount; for month 7-12 of consecutive months below the threshold the Buyer shall pay 75% of the Product Rate; after the 12th consecutive month Buyer has the right to terminate the agreement. Storage Capacity: Buyer has the right to terminate the agreement.
PC Delivery Requirements	
Measurement Period	One Contract Year
Performance Factor	95%
PC Shortfall Amount	Amount of undelivered PCs below 95% of the Yearly PC Amount

PC Replacement Cost	Determined by Buyer based on cost to replace PCs from market or from PCs in Buyer's account including penalties associated with PC Shortfall Amount.
Replacement PCs	At NV Energy's option, Supplier can provide comparable PCs to cure a PC Shortfall, in lieu of payment of PC Replacement Costs.
Purchase Options	
Early Purchase Option	Buyer has options to purchase the facility on or after the 8th or 16th, anniversaries of COD, at the greater of fair market value or a fixed price.
End of Term Purchase Option	Buyer has option to purchase facility at the end of the PPA term at the greater of fair market value or a fixed price.
Right of First Offer	Buyer has right of first offer for certain Restricted Transactions, as defined in the PPA.
Security	
Development Security	\$6,875,000 prior to PUCN approval \$19,250,000 after PUCN approval
Operating Security	\$16,502,100
Delay Damages, Deficit Damages	
Delay Damages	If Supplier does not achieve commercial operation by December 1, 2022, Supplier pays \$53,472.00 per day for days 1-60, \$106,944.00 per day for days 61-120, \$160,416.00 per day for days 121-180, that commercial operation has not been achieved. If commercial operation has not been achieved within 180 days after December 1, 2022, Buyer may terminate the PPA.
Nameplate Damages	If the Certified Nameplate Capacity Rating is less than the Expected Nameplate Capacity, Supplier will pay Deficit Damages of \$200,000 per MW below 180 MW, up to \$4,000,000. If the Certified Net Capacity Rating is greater than the Expected Nameplate Capacity Rating by more than 2%, Supplier will pay an amount of one half of the Development Security to Buyer.
Termination Rights	
Event of Default	The Non-Defaulting Party may terminate the PPA if the Defaulting Party has not cured an Event of Default within the applicable Cure Period.
PUCN Approval, Energy Choice	Buyer may terminate the PPA if it is not approved by the PUCN Approval Deadline of December 31, 2019. If the PPA is approved with conditions unacceptable to Buyer then Buyer may terminate.
Force Majeure	Buyer may terminate the PPA if Suppliers' obligations have been excused by an event of Force Majeure for longer than 12 consecutive months or 360 days in any 540 day period.

KEY PROVISIONS OF THE 300MS 8ME LLC PPA[2]

PROVISION	SOUTHERN BIGHORN SOLAR FARM PPA
Supplier	300MS 8ME LLC
Buyer	Nevada Power Company, dba NV Energy
Term	25 years
Net Capacity	300 MW
Battery Capacity	135 MW; 540 MWh over 4-hour duration
Expected Commercial Operation	September 1, 2023
Product Description	Solar photovoltaic with integrated battery storage. Buyer has rights to schedule and dispatch the Generating Facility during the Dispatchable Period. During the Full Requirements Period (hour ending 1700-2100 for June, July and August) Supplier controls the Generating Facility to maximize output.
Yearly PC Amount (Contract Year 1)	1,014,929 kPCs
Maximum Amount (Contract Year 1)	300 MWh in any hour.
Degradation	Annual Supply Amount, hourly Supply Amounts, Yearly PC Amount and Maximum Amount each decline by 0.3% per year.
Pricing	
Product Rate	$22.32 per MWh during Dispatchable Period; $145.08 per MWh during the Full Requirements Period; no escalation.
Excess Energy Rate	Fifty percent of the Product Rate.
Excess Energy	Delivered amounts above 100% of the Annual Supply Amount, adjusted for Excused Product.
Test Product Rate	50% of Product Rate.
Provisional Rate	75% of Product Rate.
Provisional Energy	Net Energy (but not Test Energy) that is delivered by Supplier to Buyer prior to the Commercial Operation Date and at the request of Buyer in increments of no less than five (5) MW up to an aggregate maximum of three hundred (300) MW.
Maximum Amount	No payment for amounts delivered above the Maximum Amount in any hour.
Energy Delivery Requirements	

[2] An 8minutenergy subsidiary.

Measurement Periods	Full Requirements Period: hour ending 1700-2100 for June, July and August; Dispatchable Period which is all times that are not Full Requirements Period;
Performance Factor (Shortfall Threshold)	Full Requirements Period Capacity Shortfall: 5% of Full Requirements Period Product, adjusted for Excused Product. Dispatchable Period Shortfall: 5% of Delivered Amounts, adjusted for Excused Product.

Shortfall	Full Requirements Period: Amount of undelivered energy below the 98% performance factor. Dispatchable Period: (i) Shortfall: if the Delivered Amounts are less than 95% of the Resource Adjusted Backcast Amount; and (ii) DAR: Dispatchable Accuracy Rate is less than 97% for 3 consecutive months and successive months thereafter. Storage Capacity: Storage Capacity is less than or equal to 90% of the Storage Contract Capacity for two consecutive Contract Years.
Shortfall Consequences	Full Requirements Period: (i) positive difference, if any, between the average Mead Index price during On-Peak hours of the Full Requirements Period and the Full Requirements Period Product Rate times the shortfall amount; (ii) if a Full Requirements Period Capacity Shortfall occurs for second consecutive year the amount of such shortfall times the Full Requirements Period Product Rate shall be deducted from the amounts due Supplier; (iii) if a third consecutive Full Requirements Period Shortfall occurs Supplier shall pay the amounts in (ii) above and Buyer shall have the right to terminate the agreement. Dispatchable Period: (i) Shortfall: positive difference, if any, between the average Mead Index price during the On-Peak hours of the Dispatchable Period and the Product Rate times the shortfall amount. (ii) DAR: after three months to six months buyer only pays for Delivered Energy not the Un-dispatched Amount; for month 7-12 of consecutive months below the threshold the Buyer shall pay 75% of the Product Rate; after the 12th consecutive month Buyer has the right to terminate the agreement. Storage Capacity: Buyer has the right to terminate the agreement.
PC Delivery Requirements	
Measurement Period	One Contract Year
Performance Factor	90%
PC Shortfall Amount	Amount of undelivered PCs below 90% of the Yearly PC Amount

PC Replacement Cost	Determined by Buyer based on cost to replace PCs from market or from PCs in Buyer's account including penalties associated with PC Shortfall Amount.
Replacement PCs	At NV Energy's option, Supplier can provide comparable PCs to cure a PC Shortfall, in lieu of payment of PC Replacement Costs.
Purchase Options	
Early Purchase Option	Buyer has options to purchase the facility on or after the 8th, 15th, or 20th anniversaries of COD, at the greater of fair market value or the amount of any outstanding indebtedness owed to Supplier's Lenders pursuant to any financing or refinancing of the Facility.
End of Term Purchase Option	Buyer has option to purchase facility at the end of the PPA term at the greater of fair market value or the amount of any outstanding indebtedness owed to Supplier's Lenders pursuant to any financing or refinancing of the Facility and to Supplier's investors.
Right of First Offer	Buyer has right of first offer for certain Restricted Transactions, as defined in the PPA.
Security	
Development Security	\$10,875,000 prior to PUCN approval \$30,450,000 after PUCN approval
Operating Security	\$27,068,800
Delay Damages, Deficit Damages	
Delay Damages	If Supplier does not achieve commercial operation by January 1, 2022, Supplier pays \$84,582.00 per day for days 1-60, \$169,167.00 per day for days 61-120, \$253,749.00 for days 121-180, that commercial operation has not been achieved. If commercial operation has not been achieved within 180 days after September 31, 2023, Buyer may terminate the PPA.
Nameplate Damages	If the Certified Nameplate Capacity Rating is less than the Expected Nameplate Capacity, Supplier will pay Deficit Damages of \$200,000 per MW below 270 MW, up to \$6,000,000. If the Certified Net Capacity Rating is greater than the Expected Nameplate Capacity Rating by more than 2%, Supplier will pay an amount of one half of the Development Security to Buyer.
Termination Rights	
Event of Default	The Non-Defaulting Party may terminate the PPA if the Defaulting Party has not cured an Event of Default within the applicable Cure Period.
PUCN Approval, Energy Choice	Buyer may terminate the PPA if it is not approved by the PUCN Approval Deadline of December 31, 2019. If the PPA is approved with conditions unacceptable to Buyer then Buyer may terminate.

Force Majeure	Buyer may terminate the PPA if Suppliers' obligations have been excused by an event of Force Majeure for longer than 12 consecutive months or 360 days in any 540 day period

KEY PROVISIONS OF SOLAR PARTNERS XI, LLC[3] PPA

PROVISION	GEMINI SOLAR PPA
Supplier	Solar Partners XI, LLC
Buyer	Nevada Power Company, d/b/a NV Energy
Term	25 years
Net Capacity	690 MW
Battery Capacity	380 MW; 1,416 MWh over 3.7-hour duration
Expected Commercial Operation	December 1, 2023
Product Description	Solar photovoltaic with integrated battery storage. Buyer has rights to schedule and dispatch the Generating Facility during the Dispatchable Period. During the Full Requirements Period (hour ending 1700-2100 for June, July and August) Supplier controls the Generating Facility to maximize output.
Yearly PC Amount (Contract Year 1)	2,226,581 kPCs
Maximum Amount (Contract Year 1)	690 MWh in any hour.
Degradation	Annual Dispatch Availability Amount, hourly Dispatch Availability Amounts each decline by 0.5% per year. Yearly PC Amount and Maximum Amount declines by 0.7% per year.
Pricing	
Product Rate	$24.79 per MWh during Dispatchable Period; $161.135 per MWh during the Full Requirements Period; no escalation.
Excess Energy Rate	Fifty percent of the Product Rate.
Excess Energy	Delivered amounts above 100% of the Maximum Amount for Contract Year, adjusted for Un-Dispatched Amount.
Test Product Rate	50% of Product Rate.
Provisional Rate	75% of Product Rate.
Provisional Energy	Net Energy (but not Test Energy) that is delivered by Supplier to Buyer prior to the Commercial Operation Date and at the request of Buyer in increments of no less than five (5) MW up to an aggregate maximum of six hundred ninety (690) MW.
Maximum Amount	No payment for amounts delivered above the Maximum Amount in any hour.
Energy Delivery Requirements	

[3] An Arevia Solar subsidiary.

Measurement Periods	Full Requirements Period: hour ending 1700-2100 for June, July and August; Dispatchable Period which is all times that are not Full Requirements Period.
Performance Factor (Shortfall Threshold)	Full Requirements Period Capacity Shortfall: 5% of Full Requirements Period Product, adjusted for Excused Product Dispatchable Period Shortfall: 5% of Delivered Amounts, adjusted for Excused Product.
Shortfall	Full Requirements Period: Amount of undelivered energy below the 95% performance factor. Dispatchable Period: (i) Shortfall: if the Delivered Amounts are less than 95% of the Resource Adjusted Backcast Amount; and (ii) DAR: Dispatchable Accuracy Rate is less than 97% for 3 consecutive months and successive months thereafter. Storage Capacity: Storage Capacity is less than or equal to 90% of the Storage Contract Capacity for two consecutive Contract Years.
Shortfall Consequences	Full Requirements Period: (i) positive difference, if any, between the average Mead Index price during On-Peak hours of the Full Requirements Period and the Full Requirements Period Product Rate times the shortfall amount; (ii) if a Full Requirements Period Capacity Shortfall occurs for second consecutive year the amount of such shortfall times the Full Requirements Period Product Rate shall be deducted from the amounts due Supplier; (iii) if a third consecutive Full Requirements Period Shortfall occurs Supplier shall pay the amounts in (ii) above and Buyer shall have the right to terminate the agreement. Dispatchable Period: (i) Shortfall: positive difference, if any, between the average Mead Index price during the On-Peak hours of the Dispatchable Period and the Product Rate times the shortfall amount. (ii) DAR: after three months to six months buyer pays an amount that is the actual DAR for those months subtracted from 0.97 times the Dispatched Amount for such month; for months 3-6 Buyer shall only pay Supplier the Dispatched Amount; for month 7-12 of consecutive months below the threshold the Buyer shall pay 75% of the Product Rate; after the 12th consecutive month Buyer has the right to terminate the agreement. In addition, if Supplier fails to meet the DAR Threshold for 36 non-consecutive months during the Dispatchable Periods Buyer will have the right to terminate. Storage Capacity: Buyer has the right to terminate the agreement.
PC Delivery Requirements	
Measurement Period	One Contract Year

Performance Factor	90%
PC Shortfall Amount	Amount of undelivered PCs below 90% of the Yearly PC Amount
PC Replacement Cost	Determined by Buyer based on cost to replace PCs from market or from PCs in Buyer's account including penalties associated with PC Shortfall Amount
Replacement PCs	At NV Energy's option, Supplier can provide comparable PCs to cure a PC Shortfall, in lieu of payment of PC Replacement Costs.
Purchase Options	
Early Purchase Option	Buyer has options to purchase the facility on or after the 10th, 15th or 20th, anniversaries of COD, at the greater of fair market value or a fixed price.
End of Term Purchase Option	Buyer has option to purchase facility at the end of the PPA term at fair market value.
Right of First Offer	Buyer has right of first offer for certain Restricted Transactions, as defined in the PPA.
Security	
Development Security	$26,750,000 prior to PUCN approval $74,900,000 after PUCN approval
Operating Security	$68,009,500
Delay Damages, Deficit Damages	
Delay Damages	If Supplier does not achieve commercial operation by December 1, 2023, Supplier pays $208,055.70 per day for days 1-60, $416,111.40 per day for days 61-120, $624167.10 per day for days 121-180, that commercial operation has not been achieved. If commercial operation has not been achieved within 180 days after December 1, 2022, Buyer may terminate the PPA.
Nameplate Damages	If the Certified Nameplate Capacity Rating is less than the Expected Nameplate Capacity, Supplier will pay Deficit Damages of $200,000 per MW below 621 MW, up to $13,800,000. If the Certified Net Capacity Rating is greater than the Expected Nameplate Capacity Rating by more than 2%, Supplier will pay an amount of one half of the Development Security to Buyer.
Termination Rights	
Event of Default	The Non-Defaulting Party may terminate the PPA if the Defaulting Party has not cured an Event of Default within the applicable Cure Period.
PUCN Approval, Energy Choice	Buyer may terminate the PPA if it is not approved by the PUCN Approval Deadline of December 31, 2019. If the PPA is approved with conditions unacceptable to Buyer then Buyer may terminate.

Force Majeure	Buyer may terminate the PPA if Suppliers' obligations have been excused by an event of Force Majeure for longer than 12 consecutive months or 360 days in any 540 day period

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, SHANE PRITCHARD, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

SHANE PRITCHARD

Subscribed and sworn to before me
this 19th day of June, 2019.

Notary Public

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

MARC D. REYES

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Third Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-06___

Prepared Direct Testimony of

Marc D. Reyes

I. INTRODUCTION

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

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

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

A. I have been employed by the Companies since May 2007 and was named Treasurer in April 2019. Before I became Treasurer, I was the Director of Resource Planning and Analysis. As Director of Resource Planning and Analysis, I was responsible for the development of the Companies' Integrated Resource Plans ("IRP") and IRP amendments, and Energy Supply Plans ("ESP") and ESP updates. I oversaw the production cost modeling and economic analysis related to intermediate and long-term planning activities of the Companies. From May 2011 to July 2017, I served as the Manager of Market Fundamentals. As the Manager of Market Fundamentals, I was responsible for the development of the market price forecasts for natural gas and wholesale purchase power. I was also responsible for the regional market fundamental analysis supporting the energy supply and resource planning functions.

More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Reyes-Direct-1**.

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

A. Yes. I have provided testimony in IRP dockets and ESP dockets before the Commission, the most recent being the Sierra's and Nevada Power's 2019-2038 Joint IRP, Docket No. 18-06003.

II. <u>OVERVIEW AND TESTIMONY ORGANIZATION</u>

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

A. I sponsor the economic analysis used in the evaluation of the resource plans in the Third Amendment to the Joint Integrated Resource Plan for 2019-2038 ("Third Amendment"). In Section III, I discuss actions that the Companies will take during the amended Action Plan period (2019-2021) to implement the projects in this Third Amendment. In Section IV, I discuss the economic analysis used in the selection of the Companies' Preferred Plan. Section V of my testimony addresses the financial plan.

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

A. In addition to Exhibit Reyes-Direct-1, I am sponsoring the following Technical Appendix Items:

- ECON-1: Loads and Resources Tables
- ECON-2: Capital Projects
- ECON-3: PWRR (Production Costs plus Capital Costs)
- ECON-4: Operating Reserves Calculation
- ECON-5: PROMOD Area Diagram
- GEN-1: Generation Unit Characteristics

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

A. Yes. The following technical appendices are confidential:

- ECON-2: Capital Projects
- GEN-1: Generation Unit Characteristics

7. Q. PLEASE EXPLAIN WHY ECON-2 AND GEN-1 ARE CONFIDENTIAL?

A. ECON-2 contains sensitive projected capital cost information related to conventional placeholder resources and GEN-1 contains the unit characteristics of the Companies' generation fleet.

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

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

9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE NEVADA ATTORNEY GENERAL'S BUREAU OF CONSUMER PROTECTION ("BCP") TO FULLY INVESTIGATE THE 2018 RESOURCE PLAN OR THE INFORMATION SET FORTH IN THESE TECHNICAL APPENDICES?

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

III. <u>RESOURCE PLANNING AND THE ACTION PLAN</u>

10. Q. PLEASE DESCRIBE THE COMPANIES' RESOURCE NEEDS OVER THE INTEGRATED RESOURCE PLANNING HORIZON.

A. Under the base case load forecast, the Companies' open capacity position in 2020 and 2021 is 1,420 megawatts ("MW") and 1,356 MW respectively. Additionally, since the filing of the Companies' 2019-2038 Joint IRP in Docket No. 18-06003, the Nevada Legislature enacted Senate Bill 358 which increases the Renewable Portfolio Standard ("RPS") from 25 percent by 2025 to 50 percent by 2030.

11. Q. ARE THE COMPANIES REQUESTING PERMISSION TO ADD COMPANY-OWNED GENERATING CAPACITY TO BEGIN TO CLOSE THESE OPEN POSITIONS?

A. No. The Third Amendment does not request approval to pursue any company-owned generating resources. Instead, the plan requests approval of three long-term renewable energy power purchase agreements ("PPAs") to address the Companies' resource requirements. The three PPAs will add 1,190 MW of solar photovoltaic

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("PV") resources with integrated battery energy storage systems co-located at each of the facilities. Combined, the battery energy storage systems will provide 590 MW of real power capability with 2,331 megawatt-hours ("MWh") of energy storage capacity.

These PPAs are discussed in Section 4 of the narrative. The Renewable Energy Plan is sponsored by Mr. Shane Pritchard.

12. Q. DO THE COMPANIES NEED TO INVEST IN TRANSMISSION RESOURCES DURING THE ACTION PLAN PERIOD?

A. Yes. First, the Companies need to construct transmission network upgrades projects to facilitate the interconnection of the three solar PV projects described above. Second, the Companies are requesting Action Plan approval to construct a 230 kilovolt ("kV") switchyard to accommodate load growth in the Apex Industrial Park in the city of North Las Vegas. Finally, the Companies are requesting approval to replace two existing 230 kV motor operated switches with three 230 kV breakers at the Machacek 230 kV substation to improve transmission reliability for service to loads served by Mt. Wheeler Power.

These transmission investments are discussed in Section 5 of the narrative. The Transmission Plan and projected project expenditures are sponsored by Mr. Sachin Verma.

13. Q. PLEASE SUMMARIZE THE ACTIVITIES FOR WHICH THE COMPANIES ARE REQUESTING AUTHORITY TO DEPLOY FUNDS DURING THE THREE-YEAR ACTION PLAN PERIOD IN PURSUIT OF THE PREFERRED PLAN?

A. In this Third Amendment, the Companies are seeking Commission approval of its Preferred Plan, including the following items:

1) Transmission projects necessary to interconnect the renewable energy projects totaling $20.6 million;
2) Construction of a new 230 kV substation at the Apex Industrial Park to serve new load, and accommodate additional transmission interconnections and distribution transformers at a total cost of $13.42 million;
3) Construction of three 230 kV breakers at the existing Machacek substation at a total cost of $6.2 million.

IV. ECONOMIC ANALYSIS

14. Q. PLEASE DESCRIBE THE METHODOLOGY USED TO PERFORM THE ECONOMIC ANALYSIS OF THE PLANS CONSIDERED IN THIS FILING.

A. The Companies' economic analysis of the renewable energy resources evaluated in the preparation of the Third Amendment begins with the Loads and Resources Tables ("L&R Tables"). A long-term forecast of annual peak loads, planning reserve requirements, and a forecast of an annual peak capacity for supply-side and demand-side resources are used to determine the open capacity position ("Open Position") for each year under base (or mid) load conditions. The Open Position is defined as any value resulting from the peak load, net of demand-side and private generation resources, plus planning reserves that is greater than the sum of the peak capacities for all of the available supply-side resources. The Companies' review of the projected yearly Open Positions determines the year or years when resources are needed and triggers the development of alternative plans (or "cases") that address the identified needs.

After developing the L&R Tables, the Companies use two economic models to evaluate the alternative plans over the planning period. The first is a production cost model, "PROMOD."[1] PROMOD simulates the operation of electric system and computes production costs (fuel, purchase power, variable and fixed costs to operate) by performing hourly, chronological economic unit commitment and dispatch of the Companies' electric production resources and market purchases to satisfy hourly load requirements in a least cost solution over the planning period. The second model used is a Companies-designed Capital Expense Recovery model ("CER"). The CER computes the annual revenue requirement for capital projects based on the costs of constructing or acquiring resources.[2]

The annual production costs from PROMOD, plus the annual revenue requirements for capital projects from the CER, are summed over the planning period for each plan. This provides the total revenue requirement over the planning period. The total revenue requirement is then discounted by the Companies' weighted cost of capital to determine the Present Worth of Revenue Requirement ("PWRR") for each of the alternative plans. A comparison of the PWRR of each alternative plan provides a basis for economically ranking the plans from least cost to most expensive. The PWRR ranking is one factor used to determine the Preferred Plan.

[1] PROMOD is a proprietary software product that the Company licenses from ABB Group.

[2] The Companies also calculate the cost of the Open Position separately in Excel model and can be found in the PROM_OUT file. The Open Position cost is the product of the open position and the Companies' capacity price forecast.

15. Q. PLEASE DESCRIBE THE PLANS THAT WERE DEVELOPED AND EVALUATED FOR THIS IRP.

A. The Company evaluated five plans in preparation of the Third Amendment:

"**All Placeholder**" Case: As is described in the narrative, the All Placeholder case uses renewable resource placeholders to satisfy the Companies' compliance with the RPS.

"**Moapa**" Case: This case includes the addition of EDF's 200 MW Moapa Solar PV facility with integrated battery energy storage capable of discharging 75 MW of real power and energy storage capacity of 375 MWh.

"**SBS**" Case: This case includes the addition of 8minutenergy's 300 MW Southern Bighorn Solar Farm PV facility with integrated battery energy storage capable of discharging 135 MW of real power and energy storage capacity of 540 MWh.

"**Arevia"** Case. This case includes the addition of Arevia's 690 MW Gemini Solar PV facility with integrated battery energy storage capable of discharging 380 MW of real power and energy storage capacity of 1,416 MWh.

"**M_S_A"** Case. This case includes the addition of the Moapa, SBS, and Arevia facilities described above for a total of 1,190 MW of solar PV and 2,331 MWh of battery energy storage capability.

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16. Q. PLEASE DESCRIBE THE COMPANIES' ASSESSMENT OF THEIR OPEN POSITIONS.

A. Under the Base Load scenario, the Companies have an Open Position every year beginning in 2019. In the All Placeholder case, the Open Position is significant. In the M_S_A case, which is the Preferred Plan, long-term obligations reduce the open position. However, even in the Preferred Plan the Companies' Open Position remains greater than 1,000 MW in every year.

17. Q. ALTHOUGH THE RENEWABLE PLACEHOLDERS HELP MANAGE THE OPEN POSITION THROUGH THE PLANNING PERIOD, OPEN POSITIONS REMAIN IN LATER YEARS. HOW WILL THE COMPANIES ADDRESS FUTURE RESOURCE NEEDS?

A. The Companies' L&R Tables show that the Companies will have additional needs, beyond 2019 through the 20 and 30-year planning periods. However, the Companies are not currently proposing resources to address these needs in the Third Amendment application. Furthermore, the Companies are not asking the Commission to approve conventional placeholder resource additions in this filing. Actions to add appropriate resources will be the subject of future IRPs or IRP amendments.

18. Q. DO THE COMPANIES ENSURE THAT ALL ALTERNATIVE PLANS MEET THE RPS THROUGH THE PLANNING PERIOD?

A. Yes. Renewable resource additions (also referred to as "renewable placeholders") are modeled throughout the planning period in each case to ensure that the Companies remain RPS compliant.

19. Q. WHAT WERE THE RESULTS OF THE ECONOMIC ANALYSIS?

A. The significant findings of the economic analysis are:

- The M_S_A produced the lowest 20-year and 30-year PWRR evaluation in the base case load forecast and the all-eligible load sensitivity.
- The Arevia case performed second in PWRR rankings in the 20-year and 30-year PWRR evaluation under both load forecasts.
- The All Placeholder case underperformed all cases in the 20-year and 30-year PWRR evaluations.

20. Q. HAVE THE COMPANIES CHANGED THE METHODOLOGY FOR DETERMINING THE CAPACITY CONTRIBUTION OF SOLAR PV RESOURCES FROM THE ASSUMPTIONS USED IN THE 2018 JOINT IRP, DOCKET NO. 18-06003?

A. No. The Companies continue to utilize the capacity contribution of solar PV using the effective load carrying capability ("ELCC") of utility scale or universal solar PV resources as presented in Docket No. 18-06003. Under the M_S_A case, universal solar PV resources contribute 33 percent of nameplate capability from 2019 through 2021, 25 percent of nameplate capability from 2022 through 2023, and 20 percent of nameplate capability from 2024 through 2048.

V. <u>FINANCE PLAN</u>

21. Q. DO THE COMPANIES HAVE THE ABILITY TO FINANCE THE TRANSMISSION PROJECTS INCLUDED IN THE THIRD AMENDMENT?

A. For both utilities, cash generated from operations should be sufficient to fund the transmission network upgrades necessary to interconnect the renewable PPAs that form the cornerstone of the Preferred Plan and the other transmission investments discussed above. Equally important, cash from operations during the 2019 – 2038 period should be sufficient to fund the capital projects set forth in the CERs for the Preferred and Alternative plans. Nevertheless, the Companies will have a continued need to access external financing in order to i) fund working capital, ii) refinance maturing debt, and iii) maintain capital structures that are appropriate for their investment grade credit ratings.

22. Q. WILL THE COMPANIES BE ABLE TO ACCESS THE CAPITAL MARKETS IN ORDER TO FINANCE THE PREFERRED OR ALTERNATIVE PLANS, IF NEEDED?

A. Yes. Of course, regulatory support is essential to ensure continued access to the debt and equity capital necessary to serve customers at just and reasonable rates. Over-reliance on the debt markets to fund future investments could lead to credit quality weakening and excessive financing costs. Regulatory support is necessary to attract equity capital, maintain a balanced capital structure, and prevent a deterioration in credit metrics.

23. Q. THE PREFERRED PLAN REQUESTS APPROVAL OF THREE LONG-TERM OBLIGATIONS. WILL THE ADDITION OF THREE NEW PPAS RESULT IN ADDITIONAL OFF-BALANCE SHEET OBLIGATIONS?

A. Yes, credit quality can be impacted by the funding requirements associated with capital expenditures and by financial commitments created by contracts such as PPAs. PPAs are also part of the rating agencies' evaluation process and have the potential to harm credit metrics, depending on the magnitude and terms of a utility's PPA portfolio.

While the addition of 1,190 MW of solar PV resources and associated battery energy storage reduce key credit metrics and could negatively affect credit ratings, prudent financial management and reasonable regulatory outcomes should be sufficient to mitigate those adverse consequences. In the 2018 IRP, both companies indicated that they intend to maintain a capital structure with an equity ratio between 50 percent and 52 percent. The Companies' financial modeling assumes regulatory approval of these equity ratios in general rate review proceedings. In light of this assumption, the amount of incremental imputed debt associated with the three PPAs and the Companies' overall debt portfolio, I do not have significant concerns about the Companies' coverage ratios.

In addition to maintaining the equity ratios described above, the Companies expect to be able to mitigate the impact of the PPAs through prudent financial management. The Companies' secured debt is rated investment grade by Moody's Investors Service and Standard & Poor's. The Companies' have maintained adequate liquidity and demonstrated the ability to successfully access the debt markets at competitive rates relative to industry peers. Maintaining access to external capital at favorable rates is critical in order to minimize customer rates. To the best of their abilities, the Companies will manage their capital structures in a way that mitigates any potential negative pressure on credit quality from the Third Amendment to the 2018 Joint IRP but, as noted above, regulatory support is an important part of the overall picture.

24. Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

STATEMENT OF QUALIFICATIONS

MARC D. REYES

My name is Marc D. Reyes. My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am the Treasurer for Nevada Power Company, d/b/a NV Energy and Sierra Pacific Power Company, d/b/a NV Energy.

I graduated from New Mexico State University with a Bachelor of Arts Degree in Economics in 2000 and earned a Certificate in Utility Management from Willamette University in 2010.

I was named Treasurer in April 2019. Prior to my current role, I was the Director of Resource Planning and Analysis from July 2017 through March 2019. I led a staff of economists, planners, engineers, and analysts to develop Integrated Resource Plans, Energy Supply Plans, and Gas Informational Reports. As Director of Resource Planning and Analysis I developed and supported supply strategies, and reported on the status of the supply plans for management review.

From May 2011 through July 2017, I was the Manager of Market Fundamentals. In that role, I was responsible for the preparation of fundamental analysis and market price forecasts for natural gas and wholesale power in the western U.S.

From May 2007 until May 2011, I was employed as an Energy Trader in Resource Optimization for NV Energy. I was responsible for executing daily to monthly wholesale power and natural gas transactions to optimize the Companies short-term portfolio. I performed market surveys to identify liquidity and obtain price discovery. I performed market research to identify new opportunities to reduce fuel and purchased power costs and worked with the credit and contracts groups to establish new counterparties. I mentored and developed junior traders.

From October 2005 until May 2007, I was employed as a Power Trader for El Paso Electric Company. I was responsible for executing real time power trades as part of the wholesale power marketing group's profit and loss book. I worked closely with the day-ahead and term traders to optimize the company portfolio in the Western Electric Coordinating Council and Southwest Power Pool regions.

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF CLARK)

I, MARC D. REYES, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

MARC D. REYES

Subscribed and sworn to before me
this 18th day of June, 2019.

NOTARY PUBLIC

S. MANNSUR-JOHNSTON
Notary Public, State of Nevada
No. 03-79990-1
My Appt. Exp. Feb. 5, 2023

SACHIN VERMA

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

Third Amendment to
2018 Joint Triennial Integrated Resource Plan

Docket No. 19-06___

Prepared Direct Testimony of

Sachin Verma

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

A. My name is Sachin Verma. I am the Director of Transmission System Planning for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS THE DIRECTOR OF TRANSMISSION SYSTEM PLANNING?

A. I am responsible for all transmission planning associated with Integrated Resource Planning ("IRP"), compliance, generator interconnections and transmission load addition functions for the Companies.

3. Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE?

A. I have a Bachelor of Science Degree in Electrical Engineering and a Master of Business Administration Degree with a focus in Finance, both from the University of Nevada, Reno. I am a registered Professional Engineer in the State of Nevada. I began my employment with the Companies as a student engineer in 2007. I have experience in transmission planning, distribution service, electric metering and system protection. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Verma-Direct-1**.

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

A Yes, I have testified in several IRPs and IRP amendments, including most recently in Docket Nos. 17-11003, 17-11004 and 18-06003.

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

A. I sponsor the section of the supply-side narrative discussing the Companies' transmission systems and associated projects, as well as Technical Appendices TRAN-1 through TRAN-4. Additionally, I support the Companies' requests (1) to construct a 230 kilovolt ("kV") switchyard to accommodate load growth in the Apex Industrial Park in the city of North Las Vegas and (2) to replace two existing 230 kV motor operated switches with three 230 kV breakers at Machacek 230 kV substation to increase reliability to Mt. Wheeler Power.

6. Q. PLEASE DESCRIBE THE EXHIBITS AND TECHNICAL APPENDICES YOU ARE SPONSORING.

A. I sponsor the following exhibits and technical appendices:

- Exhibit Verma-Direct-1 – Statement of Qualifications;
- Technical Appendix TRAN-1 – Large Generator Interconnection Agreement ("LGIA") for Moapa Solar project (200 MW proposed at Harry Allen 230 kV substation);
- Technical Appendix TRAN-2 – System Impact Study associated with the Southern Bighorn Solar 2 project (300 MW proposed at Reid Gardner 230 kV substation);
- Technical Appendix TRAN-3 – LGIA for Apex Solar (440 MW proposed at Crystal 230 kV substation);[1] and
- Technical Appendix TRAN-4 – System Impact Study associated with the Gemini Solar (250 MW proposed at Crystal 500 kV substation)

TRAN 1-4 correspond to the three renewable energy projects with which the Companies have executed power purchase agreements ("PPAs"), and for which the Companies are seeking approval as part of this filing.

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

A. No.

[1] Apex Solar is a portion of the 690 MW known as Gemini Solar.

8. Q. PLEASE EXPLAIN THE LARGE GENERATOR INTERCONNECTIONS AND ASSOCIATED NETWORK UPGRADES.

A. This filing requests approval of, amongst other things, three power purchase agreements, between Nevada Power and three separate companies developing solar photovoltaic generating projects with integrated battery storage. These three projects have four interconnection points, as set forth in the following table.

Project	**Solar PV Nameplate Capacity/Battery Capacity**	**Point of Interconnection**	**SIS**	**Facility Study**	**LGIA**
Moapa	200 MW/ 75 MW	Harry Allen 230 kV	Complete	Complete	Complete
Southern Bighorn Solar	300 MW/ 135 MW	Reid Gardner 230 kV	Complete	In Process	
Gemini Solar	Total: 690 MW/ 380 MW				
	Point 1: 440 MW/242 MW	Crystal 230 kV	Complete	Complete	Complete
	Point 2: 250 MW/138 MW	Crystal 500 kV	Complete	In Process	

Nevada Power has entered into an LGIA with EDF Renewables for the interconnection of the Moapa Solar project at Harry Allen 230-kV substation. Nevada Power has also entered into an LGIA with Arevia Power for the interconnection of 440 MW at the Crystal 230 kV bus. Nevada Power has not yet entered into an LGIA with Arevia Power for the proposed interconnection of 250 MW at the Crystal 500 kV bus. Nor has Nevada Power entered into an LGIA with 8minute Energy for the interconnection of the 300-MW Southern Bighorn Solar project at the Reid Gardner 230-kV bus. System Impact Studies have been completed for both projects, and the proposed interconnections are in the Facilities

Study stage. The Southern Bighorn Solar interconnection is being conducted pursuant to Nevada Power's open access transmission tariff ("OATT") and is subject to specific timelines. As explained in the question and answer 10, the interconnection of 250 MW at the Crystal 500-kV bus is not subject to the same timelines.

9. Q. WHY ARE THE COMPANIES RESPONSIBLE FOR THE COSTS OF NETWORK UPGRADES REQUIRED TO INTERCONNECT A RENEWABLE PROJECT TO THE TRANSMISSION GRID?

A. FERC has determined that facilities that are not directly and exclusively required to interconnect a generator to the transmission system shall be classified as network upgrades, and it has determined how the costs of network upgrades will be 1) securitized, and 2) allocated. FERC has determined as a matter of policy that even though driven by requests for interconnection, network upgrades are considered improvements to the overall system. Thus, the associated costs are allocated to the interconnecting electric utility, and then reflected in FERC-jurisdictional transmission rates as well as state-jurisdictional bundled rates. Examples of network upgrades are the construction of a substation on an existing transmission line in order to interconnect a generator, a terminal addition at an existing substation that is configured as a ring or breaker and a half or an upgrade to an existing transmission element in the system due to the injection of additional generation. FERC's policy on network upgrades is reflected in the Companies' OATT.

10. Q. PLEASE EXPAND ON THE TIMELINES ASSOCIATED WITH THE SYSTEM IMPACT STUDY FOR A 250-MW INTERCONNECTION AT THE CRYSTAL 500-KV BUS.

A. As noted above, the Gemini project has two distinct interconnection points, one of which is Crystal 500 kV switchyard. This interconnection point is part of the Navajo Western Transmission System which is a jointly owned project among the U.S. Bureau of Reclamation, NV Energy and Los Angeles Department of Water and Power. The interconnection process associated with the Navajo Transmission System does not have set FERC timelines. Significant review and approvals are required by both the Western Arizona Transmission System technical planning group and the Navajo Transmission Engineering and Operating Committee.

At this time, the System Impact Study has been completed in accordance with procedures under the Navajo Transmission System, and the Facilities Study is in process. Committee discussions, review and recommendations can affect the timeline associated with the study process.

11. Q. PLEASE SUMMARIZE THE NEED FOR THE APEX 230-KV SWITCHYARD.

A. The proposed Apex 230-kV switchyard is required to initially connect a 13-MW load that will be served at the transmission level. The switchyard will also accommodate an additional transmission terminal that will be available for other transmission level connections, as well as a distribution transformer to serve developable land in the area. The construction of a switchyard that can accommodate a distribution transformer is consistent with transmission and distribution area plans. A new substation enhances distribution system optionality and reliability as the distribution network between and among the Speedway, Gypsum and the new substation is built out.

12. Q. ARE THERE ANY ALTERNATIVES TO THE 230-KV SWITCHYARD FOR SERVING THE PROPOSED NEW LOAD DISCUSSED IN QUESTION AND ANSWER 11?

A. The Companies did study a 138-kV radial line from Pecos Substation as an alternative; however, there are currently six transmission lines in this corridor: one 138 kV, four 230 kV and one 500 kV. Permitting through this corridor was deemed to be very difficult and would not meet the timeline associated with the load service to the new customer or the plan for future distribution sourcing. The specific issues with permitting a new 138-kV line were:

1) Part of the new radial line would cross land owned/controlled by the U.S. Air Force (USAF) in conjunction with the Nellis Small Arms Range. Approval would be required from the USAF, which would include approvals from the local base, the central lands department and Washington D.C. Historically, the USAF has not approved anything in proximity to the Nellis Small Arms Range.

2) Part of the new radial line would cross land owned and controlled by the State of Nevada for the National Guard. Approval would be required from both the State of Nevada and the National Guard, which would be a lengthy process. Historically, the Companies have faced opposition from the State and National Guard when crossing this land.

Additionally, the 138-kV line would be radial and both the transmission level service and distribution level service would be subject to an outage for any event on the line. In order to provide two sources to the 138-kV option, a new 138-kV line from Gypsum Substation would be required, but available terminals currently do not exist at this site. Based on these complications with the 138-kV option, the 230-kV option was pursued.

13. Q. PLEASE SUMMARIZE THE EXISTING LOAD AND DISTRIBUTION LOAD REQUESTS RECEIVED IN THE APEX AREA AND THE EXISTING CAPACITY OF NEARBY DISTRIBUTION SUBSTATIONS.

A. Currently, two banks serve the majority of load in the Apex area. Speedway Substation is located on the southern end of the Apex Industrial Park, and Gypsum Substation is located in the middle of the park. The majority of Apex is served from the Gypsum Substation. Based on both signed and pending contracts, the Gypsum transformer bank is anticipated to overload in 2021 and the Speedway transformer bank is anticipated to overload in 2020. At this time, additional banks could be added to each substation to accommodate future load growth. With approximately seven miles between the two distribution substations, the cost of line extensions can cause a financial barrier to entry. Thus, in addition to the benefits discussed above, the new Apex Substation would ease the connection of load growth by reducing the cost of line extensions and creating increased reliability with networked distribution between the three distribution sources.

14. Q. PLEASE SUMMARIZE THE NEED FOR THE 230-kV BREAKER ADDITION AT MACHACEK 230-kV SUBSTATION.

A. Machacek substation is jointly owned by Sierra and Mt. Wheeler Power. Sierra owns the transmission or source side of the substation, and Mt. Wheeler owns the load or distribution side of the substation. Mt. Wheeler is a transmission customer who purchases energy off system to serve its load. The total Mt. Wheeler load served from Machacek substation is approximately 20 MW. Machacek is on the 230-kV system between Gonder and Frontier Substations; 66 line miles from Gonder and 49 line miles from Frontier. Any disturbance or maintenance that occurs on the 115 mile stretch between Gonder and Frontier results in an outage to Mt. Wheeler. There are motor operated switches at Machacek connecting to each source, but they do not operate properly and can only be switched manually which requires an outage to Mt. Wheeler. Replacing the motor operated switches with a three circuit breaker ring configuration creates an isolation point where any single disturbance on the entire 115-mile stretch of 230 kV leaves the Machacek load intact. Additionally, breaker and substation maintenance can be performed on the 230-kV sources to Machacek without interruption to Mt. Wheeler load.

15. Q. ARE THERE ANY ALTERNATIVES TO THE 230-kV BREAKER ADDITION AT MACHACEK 230-kV SUBSTATION.

A. None that will provide the reliability of power circuit breakers. One alternative would be to replace the motor operating switches with new working load breaking switches. This alternative would solve the interruptions associated with planned maintenance on the 230-kV transmission, but would not address the reliability of unplanned outages that could occur on the 115-mile stretch of 230-kV transmission.

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

A. Yes it does.

STATEMENT OF QUALIFICATIONS
SACHIN VERMA

My name is Sachin Verma. My business address is 6100 Neil Road, Reno, Nevada. I have been employed with Sierra Pacific Power Company ("Sierra" or “the Company”) since 2007. I am currently the Director of Transmission System Planning for NV Energy.

I have been in a transmission planning management role since June of 2015 and have worked as a transmission planning engineer for a cumulative three years. As a transmission planning engineer I have performed studies for significant load and generation additions as well as assisted in the compilation of NERC Compliance studies focused on the reliability of the Company’s transmission grid and its ability to serve its customers.

Also, I have worked in Electric Meter Operations as both a supervisor and an engineer. In this position, I inspected installation of renewable generation, reviewed and approved electrical panels for new service and designed metering installation for high voltage generation projects. As a distribution engineer I worked with commercial and residential customers to analyze power quality concerns, performed distribution design for equipment replacement and additions and coordinated fuse protection on the system.

I am a Registered Professional Engineer in Nevada -- License #021884. I graduated from the University of Nevada, Reno in 2008 with a Bachelor of Science Degree in Electrical Engineering focused in power systems and in 2014 with a Master of Business Administration focused in finance.

By virtue of my employment, background, experience and education, I am a qualified witness in regard to the NV Energy's system and all transmission planning issues associated with the Companies' PUCN and FERC filings.

AFFIRMATION

STATE OF NEVADA)
) ss.
COUNTY OF WASHOE)

I, SACHIN VERMA, do hereby swear under penalty of perjury the following:

That I am the person identified in the attached Prepared Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this affirmation; that I have reviewed and approved any modifications after the date of this affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

SACHIN VERMA

Subscribed and sworn to before me
this 19th day of June, 2019.

LYNN D'INNOCENTI
Notary Public - State of Nevada
Appointment Recorded in Washoe County
No: 13-10786-2 - Expires May 2, 2021

Lynn D'Innocenti
NOTARY PUBLIC