

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 integrated resource plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027.

Docket No. 24-05 _____

VOLUME 3 OF 29

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

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DR. SANEM SERGICI

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 ____

Prepared Direct Testimony of

Dr. Sanem Sergici

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Sanem Sergici. I am a Principal at The Brattle Group. My business address is One Beacon Street, Boston, Massachusetts 02108. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, "NV Energy" or the "Companies").

2. Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal of The Brattle Group ("Brattle"). Brattle is an economic and management consulting firm with offices in fourteen locations globally and with more than 500 employees. Brattle's electricity and regulated energy practice has been at the core of our consulting services for more than thirty years and is Brattle's largest industry practice. Its practices pertain to (i) regulatory economics, finance and rates, (ii) wholesale markets and planning, and (iii) energy litigation and regulatory disputes.

3. Q. **PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.**

A. I received my Ph.D. in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. I received my M.A. in Economics from Northeastern University and B.S. in Economics from Middle East Technical University (METU) in Ankara, Turkey.

4. Q. **PLEASE DESCRIBE YOUR WORK EXPERIENCE IN THE UTILITY INDUSTRY.**

A. I am an energy economist with twenty years of consulting and energy research experience. My consulting practice is focused on understanding customer adoption of and response to innovative rate designs, distributed energy resources, and emerging technologies. I regularly assist our clients in matters related to rate design, electrification pathways, utility program screening, grid modernization investments, load forecasting, and resource planning. I have led studies and authored reports and regulatory filings on matters such as the benefits and costs of utility programs, associated customer rate impacts, appropriate frameworks for assessing the cost-effectiveness of new utility initiatives, and the system impacts of electrification and DSM adoption across North America. I have a diverse client base including utilities, regulators, independent system operators and technology companies. I have submitted testimony on behalf of my clients and before the regulatory commissions across North America such as those of Washington, Iowa, Wisconsin, Massachusetts, and New Hampshire among others. I regularly publish in academic and industry journals and present at industry events. My statement of qualifications is attached as **Exhibit Sergici-Direct-1**.

1 5. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY
2 WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA
3 (“COMMISSION”)?

4 A. No, I have not.
5

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

7 A. The purpose of my testimony is to present the results of a rate impact analysis for
8 NV Energy’s Demand-Side Management (“DSM”) Plan. There are multiple DSM
9 scenarios that NV Energy has prepared, as per the Commission’s order in Docket
10 No. 21-06001. My testimony provides an overview of the DSM plans, the rate
11 impact methodology and the final results of the rate impact analysis. The technical
12 exhibits I sponsor in conjunction with this testimony provide the granular detail for
13 the rate impact analysis.
14

15 7. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

16 A. I am sponsoring or co-sponsoring the following Exhibits and Technical
17 Appendices:

18 **Exhibit Sergici-Direct-1:** Resume and Relevant Qualifications

19 **Technical Appendix DSM-30:** DSM Rate Impact Analysis Report

20 **Technical Appendix DSM-31:** DSM Rate Impact Analysis Model
21

22 8. Q. HOW IS YOUR TESTIMONY ORGANIZED?

23 A. In section II, I provide an overview of the DSM rate impact analysis. Section III
24 presents the results of the Conventional DSM Rate Impact analysis. Section IV
25 presents the results of the Docket No. 21-06001 Order DSM Rate Impact Analysis.
26
27

II. OVERVIEW OF THE RATE IMPACT ANALYSIS

9. Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NV ENERGY'S DSM PLAN.

A. NV Energy is proposing a DSM plan for the 2025-2027 action period as part of its 2024 Integrated Resource Plan. The plan includes thirteen programs aimed at encouraging energy efficiency ("EE") and demand response ("DR"). These programs will be implemented across the residential and commercial customer classes for the Companies.

10. Q. PLEASE DESCRIBE THE DSM SCENARIOS THAT NV ENERGY HAS PREPARED.

A. NV Energy has prepared a DSM plan that it is proposing as part of its IRP filing. In addition, to produce the DSM rate impact analysis requested in the Commission's Order in Docket No. 21-06001, NV Energy has prepared three additional scenarios. In total, the four DSM scenarios are as follows:

- **Proposed DSM (Grid Value):** This scenario reflects the Companies' proposed DSM (Grid Value) portfolio in this 2024 IRP, which produces demand response reduction and DSM savings that equal approximately 0.7 percent of the sales forecast and approximately 175 MW of flexible demand response.
- **Proposed DSM (Grid Value) + 20%:** This scenario is derived by increasing the actual proposed DSM budget by 20 percent. This results in higher DSM savings and reduces sales compared to the Proposed DSM (Grid Value) scenario.
- **1.1% (Traditional) DSM:** This scenario is consistent with the most recent savings goal the Companies used and assumes DSM savings that equal 1.1 percent of sales in the load forecast.

- **No DSM:** This scenario assumes no new DSM programs, therefore, results in no new DSM savings in the load forecast going forward.

11. **Q. PLEASE EXPLAIN THE PURPOSE OF A DSM RATE IMPACT ANALYSIS.**

A. Electric utilities often implement DSM programs that are paid for through customer rates. However, such programs offer benefits to all customers such as avoided capacity and energy costs which have the impact of lowering customer rates.¹ Thus, a rate impact analysis provides an accounting of the DSM program costs and its associated benefits to gauge how customer rates may be impacted over time.

12. **Q. PLEASE DESCRIBE HOW YOU HAVE CONDUCTED THE RATE IMPACT ANALYSIS FOR THE DSM SCENARIOS.**

A. I conducted the rate impact analysis for NV Energy's DSM Plan in two parts:

Part 1: Conventional DSM Rate Impact Analysis. This analysis provides the typical rate impact analysis conducted in many jurisdictions and follows the guidance of The National Standard Practice Manual (NSPM) framework for assessing the cost-effectiveness of energy efficiency programs.² This part of the analysis provides a calculation of rate changes which will be experienced by all customers due to the DSM program costs and lost utility revenues, net of avoided costs due to energy and capacity benefits to the system.

Part 2: Docket No. 21-06001 Order DSM Rate Impact Analysis. This analysis is conducted in response to the Commission Order that requested a DSM rate impact analysis. The Order stated: "The Commission approves

¹ DSM programs also have the impact of reducing emissions, but they are not discussed here as they don't have an impact on rates at this time.

² National Efficiency Screening Project (NESP). *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*, August 2020, available at <https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/> ("NSPM").

BCP’s recommendation that NV Energy should be required to file a rate impact analysis, including a change case, in the next DSM Action Plan with the process changes outlined by NV Energy on rebuttal.”³ BCP’s recommendation was that “NV Energy develop and file a change or side case for the rate impact analysis that shows a **20 percent increase** in DSM for the modeled period in order to inform any Commission decisions on increasing future DSM program levels.”⁴ The methodology employed for this rate impact analysis calculates and compares the average *all-in rates* at the NV Energy System level under the **three DSM scenarios listed above** to the average rate in the **No DSM** scenario. This approach is different from the conventional analysis outlined above as it accounts for changes in the supply mix and dispatch associated with meeting the varied levels of DSM.

Technical Appendix DSM-30 provides detail on the assumptions, data and methodology used for both parts above.

13. Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF YOUR METHODOLOGY FOR THE CONVENTIONAL DSM RATE IMPACT ANALYSIS.

A. The conventional DSM rate impact analysis largely utilizes the results of the cost-effectiveness tests for the DSM programs in NV Energy’s ACE Guru model for Nevada Power and Sierra, respectively. The rate impact accounts for the cost of the DSM programs as a factor that applies upward pressure to customer rates. These costs include implementation costs, utility administrative costs, incentives and rebates that NV Energy would incur to run the DSM programs. The energy-related benefits as a result of the programs would apply downward pressure to customer

³ March 8, 2022, Corrected Modified Final Order at 115-16.

⁴ *Id.* (emphasis added).

rates. These include avoided energy and avoided capacity costs as a result of DSM, which could potentially reduce utility costs in the long run and, in turn, reduce rates. The analysis also accounts for lost utility revenues as a result of customers consuming less energy. This lost revenue would still need to be recovered to meet utility's revenue requirement, but this time through lower sales, and puts an upward pressure on rates. The final rate impact is the net impact of DSM costs, benefits and lost revenues. While the costs will be incurred only for the 2025-2027 action plan period, the effect of benefits and lost revenues will propagate throughout the period that these programs are to be in effect. The final rate impacts are calculated by dividing the associated DSM costs and impacts by total load for a given class. I conducted this analysis for the Residential, Commercial and Industrial classes for both Nevada Power and Sierra. Technical Appendix DSM-30 provides detail on the assumptions, data and methodology used for both parts above.

14. Q. WHAT IS THE PREMISE OF THE DOCKET NO. 21-06001 ORDER DSM RATE IMPACT ANALYSIS?

A. The premise of this analysis is that different levels of DSM may lead to different planned resource buildouts and/or different dispatch of existing resources in resource planning. The conventional DSM rate impact analysis outlined above assumes that marginal costs of providing service are static regardless of the level of DSM. However, in all likelihood, that is not the case. The Docket No. 21-06001 Order DSM rate impact analysis accounts for the change in investment decisions by running separate capacity expansion models for different DSM scenarios and integrates resulting capital and production costs in the financial model to develop total revenue requirement for the utility.

15. Q. DID YOU DEVELOP THE CAPACITY EXPANSION AND FINANCIAL
MODELING RESULTS TO COMPLY WITH THE DOCKET NO. 21-06001
ORDER DSM RATE IMPACT ANALYSIS?

A. No, I did not. I utilize the outputs produced by the NV Energy resource planning
and finance teams to develop the DSM Rate Impact analysis.

16. Q. PLEASE PROVIDE A HIGH LEVEL OVERVIEW OF YOUR
METHODOLOGY FOR THE DOCKET NO. 21-06001 ORDER DSM RATE
IMPACT ANALYSIS.

A. Per the Commission Order, the goal of this part of the analysis is to compare the
average *all-in* rates between the Proposed DSM (Grid Value) and Proposed DSM
(Grid Value) + 20% scenarios and against the *all-in* rate under the No DSM
scenario. The 1.1% DSM scenario rate impact was also analyzed for illustrative
purposes and because that scenario was used to create the four alternative supply
plans. I worked closely with NV Energy's resource planning team, which
completed different capacity expansion and dispatch model runs, and NV Energy's
finance team, which has incorporated these resource and dispatch costs into the
financial model to obtain the total revenue requirements associated with the DSM
plans at the utility level. The latter step was necessary because the IRP resource
and dispatch costs resulting from different DSM scenarios would not be completely
incremental to the existing capital and operating expenditures in the financial
model, therefore, could not be represented as "incremental rate impacts." For this
reason, these IRP capital and production expenses associated with different DSM
scenarios had to flow through the financial model to determine the final revenue
requirements at the utility level and ascertain the average all-in rates resulting from
different DSM plans.

The rate impact calculations were relatively straightforward for the 1.1% DSM and No DSM Scenarios as the NV Energy resource planning team has built out capacity expansion and production models for each scenario and finance team has fully incorporated the 1.1% DSM and No DSM scenarios in the financial model.⁵

The Proposed DSM (Grid Value) and Proposed DSM (Grid Value) + 20% scenarios are treated differently as these two scenarios were implemented as load sensitivities to the 1.1% DSM plan. This means that the two proposed DSM scenarios have the same resource buildout as the 1.1% DSM plan but with differing resource dispatch to meet the respective levels of DSM.⁶ Therefore, for these two scenarios, I used the revenue requirement for the 1.1% DSM scenario as the baseline but make three adjustments to accurately reflect the revenue requirements for the Proposed DSM (Grid Value) and Proposed DSM (Grid Value) + 20% scenarios:

- The first adjustment accounts for the difference in dispatch costs for the two scenarios relative to the 1.1% DSM.
- The second adjustment accounts for the difference in DSM program budgets between the two DSM scenarios and the 1.1% DSM.
- The third adjustment reflects the difference in capacity costs between the two DSM scenarios and the 1.1% DSM.⁷

These adjustments allow me to compare the all-in electric rates for the four DSM scenarios. The detailed methodology of this analysis is provided in Technical Appendix DSM-30.

⁵ The Companies' supply plans including the Base Case and the four alternative cases are modeled on the load forecast assuming 1.1 percent DSM savings. The Companies created a separate supply plan resource buildout for the No DSM plan to more accurately model a substantial increase in load in the absence of the action plan DSM savings.

⁶ NV Energy's rationale for keeping the same resource buildout for the proposed DSM (Grid) Value scenarios as for the 1.1 DSM scenario was that the savings levels are not too disparate among the 1.1% DSM, Proposed DSM (Grid Value) and Proposed DSM (grid Value) + 20% cases to warrant a change in the supply plan resources buildout.

⁷ As mentioned earlier, NV Energy's resource planning team implemented the Proposed DSM (Grid Value) and Proposed DSM (Grid Value)+20% scenarios as load sensitivities to the 1.1% DSM Scenario. This adjustment was made to account for any avoided or incurred capacity costs for these two scenarios relative to the 1.1% DSM scenario.

III. RESULTS FOR CONVENTIONAL DSM RATE IMPACT ANALYSIS

17. Q. PLEASE PROVIDE THE RESULTS OF THE CONVENTIONAL DSM RATE IMPACT ANALYSIS.

A. The table below summarizes results of the conventional DSM rate impact analysis for Nevada Power and Sierra. It shows the net rate impact for each DSM scenario for the Residential, Commercial and Industrial customer classes across both Companies. The first column presents the average net rate impact for the first three years of the action plan period, 2025 through 2027. The second column shows the average net rate impact for the next five years of the time horizon, which represents the medium-term impact of the DSM programs. The last column represents the long-term average net rate impact. While the table shows individual rate impact statistics for each scenario, customer class and utility, there are some common trends to note. The first three-year average rate impact is positive across all cases. In this case, a positive rate impact implies a rate increase for customers. This impact ranges from over half a cent per kWh for Nevada Power Residential customers to approximately two-tenths of a cent per kWh for Sierra's industrial customers. This positive rate impact is not unsurprising because the 2025 through 2027 period is when Nevada Power and Sierra will incur program costs to run the DSM programs. The following five years largely exhibit lower rate decreases for customers, with some minimal rate increases. These range from a quarter cent per kWh decrease to one-tenth of a cent increase. The slight decreases show the capacity and energy benefits as a result of the DSM programs that will help offset any loss in revenue from customers reducing consumption. The long-term average rate impact exhibits minimal rate increases for customers. This is largely a combination of the conclusion of a large share of DSM programs concluding in the outer years resulting in the decreased impact of energy and capacity benefits accompanied by

the relative dominance of lost utility revenues. Thus, the average rate impact shows a rate increase, albeit not substantial. The detailed results of this analysis and the accompanying explanations, as well as annual rate impacts by DSM scenario, customer class and utility are available in Technical Appendix DSM-30. The full analysis itself is available in Technical Appendix DSM-31.

TABLE LF-1
Conventional DSM Rate Impact Summary – Nevada Power and Sierra (\$/kWh)

	First 3 year avg (2025-2027)	Next 5 year avg (2028-2033)	15 year avg (2025-2040)
NPC - Residential			
Rate Impact due to 1.1% DSM Only	\$0.0055	-\$0.0006	\$0.0010
Rate Impact due to Proposed DSM Only	\$0.0039	-\$0.0020	\$0.0000
Rate Impact due to Proposed + 20% DSM Only	\$0.0046	-\$0.0024	\$0.0000
NPC - Commercial			
Rate Impact due to 1.1% DSM Only	\$0.0047	\$0.0004	\$0.0013
Rate Impact due to Proposed DSM Only	\$0.0033	-\$0.0009	\$0.0004
Rate Impact due to Proposed + 20% DSM Only	\$0.0039	-\$0.0011	\$0.0004
NPC - Industrial			
Rate Impact due to 1.1% DSM Only	\$0.0042	\$0.0009	\$0.0015
Rate Impact due to Proposed DSM Only	\$0.0030	-\$0.0003	\$0.0006
Rate Impact due to Proposed + 20% DSM Only	\$0.0035	-\$0.0003	\$0.0007
SPPC - Residential			
Rate Impact due to 1.1% DSM Only	\$0.0036	-\$0.0005	\$0.0005
Rate Impact due to Proposed DSM Only	\$0.0035	-\$0.0011	\$0.0002
Rate Impact due to Proposed + 20% DSM Only	\$0.0042	-\$0.0014	\$0.0003
SPPC - Commercial			
Rate Impact due to 1.1% DSM Only	\$0.0026	\$0.0000	\$0.0005
Rate Impact due to Proposed DSM Only	\$0.0024	-\$0.0006	\$0.0003
Rate Impact due to Proposed + 20% DSM Only	\$0.0029	-\$0.0007	\$0.0003
SPPC - Industrial			
Rate Impact due to 1.1% DSM Only	\$0.0022	\$0.0002	\$0.0006
Rate Impact due to Proposed DSM Only	\$0.0020	-\$0.0003	\$0.0003
Rate Impact due to Proposed + 20% DSM Only	\$0.0021	-\$0.0004	\$0.0003

IV. RESULTS FOR DOCKET NO. 21-06001 ORDER DSM RATE IMPACT ANALYSIS

18. Q. PLEASE PROVIDE THE RESULTS OF THE DOCKET NO. 21-06001 ORDER DSM RATE IMPACT ANALYSIS FOR NEVADA POWER.

A. As mentioned above in the methodology for this analysis, I calculated the average all-in electric rate for each of the DSM scenarios. For the No DSM and 1.1% DSM scenario, this is simply a function of the revenue requirements and load forecasts for the respective scenarios. For the Proposed DSM (Grid Value) and Proposed DSM (Grid Value) + 20% scenarios, it is imputed using the revenue requirement for the 1.1% DSM scenario as a baseline and then making the three above-referenced adjustments to it.

The table below summarizes the results for the all-in effective electric rates for Nevada Power. All three DSM scenarios exhibit higher all-in electric rates than the No DSM scenario in the short, medium and long term. Among the three DSM scenarios, the Proposed DSM (Grid Value) and Proposed DSM (Grid Value) + 20% scenarios consistently exhibit lower all-in electric rates for Nevada Power in the short, medium and long term than the 1.1% DSM scenario. This is potentially the result of the combination of lower DSM programs costs coupled with more targeted and higher capacity savings as well as savings experienced due to differing dispatch under the Proposed DSM (Grid Value) and Proposed DSM (Grid Value) +20% relative to the 1.1% DSM. Comparing the rates of the Proposed DSM (Grid Value) against Proposed DSM (Grid Value) + 20% is less conclusive. The Proposed DSM (Grid Value) delivers a lower rate in the short term but a higher rate in the medium term than the Proposed (Grid Value) +20% DSM. This can be explained by the higher DSM expenditures of the Proposed DSM (Grid Value) +20% scenario

during the action plan period, which generate additional savings in the medium term. The long term rates of the two scenarios are the same.

The details of this analysis for Nevada Power and the class-wise breakdown of the results are presented in Technical Appendix DSM-30. The full analysis itself is available in Technical Appendix DSM-31.

TABLE LF-2
All-In Average Electric Rate by DSM Scenario – Nevada Power (Nominal \$/kWh)

	First 3 year avg (2025-2027)	Next 5 year avg (2028-2033)	15 year avg (2025-2040)
Nevada Power			
No DSM	\$0.1071	\$0.1183	\$0.1257
Proposed DSM	\$0.1090	\$0.1195	\$0.1274
Proposed +20% DSM	\$0.1093	\$0.1191	\$0.1274
1.1% DSM	\$0.1099	\$0.1204	\$0.1280

19. Q. PLEASE PROVIDE THE RESULTS OF THE DOCKET NO. 21-06001 ORDER DSM RATE IMPACT ANALYSIS FOR SIERRA.

A. The methodology for Sierra is identical to that outlined for Nevada Power above. I calculated the average all-in electric rates for the four DSM scenarios, summarized in the table below.

Similar to the observation for Nevada Power, the No DSM scenario exhibits a lower rate than the DSM scenarios in the short and medium term. However, it exhibits a higher rate in the long term. The interplay between the Proposed DSM (Grid Value) and Proposed DSM (Grid Value) + 20% is also similar to that observed for Nevada Power. The Proposed DSM (Grid Value) delivers a lower rate in the short term but

a higher rate in the medium term than the Proposed DSM (Grid Value) + 20%. This can be explained by the higher DSM expenditures of the Proposed DSM (Grid Value) + 20% scenario during the action plan period, which generate additional savings in the medium term. The long term rates of the two scenarios are the same.

As a general observation, in the short-term, the Proposed DSM (Grid Value) exhibits an identical rate to the 1.1% DSM scenario but the Proposed DSM (Grid Value) + 20% results in a marginally higher rate than the 1.1% DSM. In the medium term and long term, the Proposed DSM (Grid Value) and Proposed DSM (Grid Value) + 20% scenarios result in lower all-in rates relative to the 1.1% DSM.

The details of this analysis for Sierra and the class-wise breakdown of the results are presented in Technical Appendix DSM-30. The full analysis itself is available in Technical Appendix DSM-31.

TABLE LF-3

All-In Average Electric Rate by DSM Scenario – Sierra (Nominal \$/kWh)

	First 3 year avg (2025-2027)	Next 5 year avg (2028-2033)	15 year avg (2025-2040)
Sierra			
No DSM	\$0.0913	\$0.1088	\$0.1140
Proposed DSM	\$0.0947	\$0.1116	\$0.1129
Proposed +20% DSM	\$0.0951	\$0.1114	\$0.1129
1.1% DSM	\$0.0947	\$0.1123	\$0.1136

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20. Q. WOULD ONE EXPECT TO SEE SUCH RESULTS FOR DSM PROGRAMS?

A. The results of the rate impact analysis for the 1.1% DSM, Proposed DSM (Grid Value) and Proposed DSM (Grid Value) + 20% are reasonable. While there is some nuance in the annual rates due to the DSM program spend and accompanying capacity and dispatch benefits in any given year, the general trend shows that 1.1% DSM result in higher all-in rates over time. Also, the No DSM scenario appears to result in lower all-in rates generally (except in the long term for Sierra).

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

A. Yes.

EXHIBIT SERGICI-DIRECT-1

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Dr. Sanem Sergici is a Principal in The Brattle Group's Boston, MA office specializing in innovative retail rate design and economic analysis of distributed energy resources (DERs). She regularly assists her clients in matters related to electrification, grid modernization investments, emerging utility business models and alternative ratemaking mechanisms.

Dr. Sergici has been at the forefront of the design and impact analysis of innovative retail pricing, enabling technology, and behavior-based energy efficiency pilots and programs across North America. She led numerous studies in these areas that were instrumental in regulatory approvals of grid modernization investments and smart rate offerings for electricity customers. She also has significant expertise in resource planning, development of load forecasting models and energy litigation.

Dr. Sergici regularly publishes in academic and industry journals and presents at industry events. She received her PhD in Applied Economics from Northeastern University in the fields of applied econometrics and industrial organization. She received her MA in Economics from Northeastern University, and BS in Economics from Middle East Technical University (METU), Ankara, Turkey.

AREAS OF EXPERTISE

- Electrification
- Innovative Retail Electricity Pricing
- Grid Modernization
- Distributed Energy Resources
- Decarbonisation Pathways and Resource Planning
- Utility Regulatory and Business Models
- Demand Forecasting

EXPERT TESTIMONY AND REGULATORY FILINGS

Testimony filed before the Federal Energy Regulatory Commission, Docket no. ER24-000, in the matter of Submission of Revisions to 2024 Rate Schedule A, on behalf of Basin Electric Power Cooperative, March 25, 2024.

Testimony before the Iowa Utilities Board, Docket No. RPU – 2023 – 0002, on behalf of Interstate Light and Power Company, October 12, 2023.

Sur - Surrebuttal Testimony pre-filed before the Public Service Commission of Wisconsin, Docket No. 6680-UR-124, in the matter of Wisconsin Power and Light Company Application for Authority to Adjust Electric and Natural Gas Rates for 2024 and 2025 Test Years, on behalf of Wisconsin Power and Light Company, September 26, 2023.

Surrebuttal Testimony pre-filed before the Public Service Commission of Wisconsin, Docket No. 6680-UR-124, in the matter of Wisconsin Power and Light Company Application for Authority to Adjust Electric and Natural Gas Rates for 2024 and 2025 Test Years, on behalf of Wisconsin Power and Light Company, September 25, 2023.

Rebuttal Testimony pre-filed before the Public Service Commission of Wisconsin, Docket No. 6680-UR-124, in the matter of Wisconsin Power and Light Company Application for Authority to Adjust Electric and Natural Gas Rates for 2024 and 2025 Test Years, on behalf of Wisconsin Power and Light Company, September 19, 2023.

Report filed before Massachusetts DPU, “A Review of National Grid’s Load Forecasting Methodology,” report filed on behalf of National Grid in the Company’s Future Grid Plan, September 2023.

Report filed before Massachusetts DPU, “An Assessment of National Grid Electric Sector Modernization Plan,” report filed on behalf of National Grid in the Company’s Future Grid Plan, September 2023.

Report filed before Massachusetts, “An Assessment of National Grid Electric Sector Modernization Plan,” report filed on behalf of National Grid, August 31, 2023.

Report filed before Massachusetts, “A Review of National Grid’s Load Forecasting Methodology,” report filed on behalf of National Grid, August 30, 2023.

Before the New Jersey Board of Public Utilities, “New Jersey Energy Master Plan Ratepayer Impact Study,” report filed August 2022 (with G. Kavlak, K. Spees, R. Janakiraman).

Before the British Public Utilities Commission, “A Review of BC Hydro’s Optional Residential TOU Rate,” report filed on behalf of BC Hydro in the Company’s Optional Residential Time-of-Use Rate Application, February 21, 2023 (with R. Hledik).

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 21-078, In the matter of Electric Make Ready and Demand Charge Alternative Proposals, on behalf of the New Hampshire Department of Energy, February 28, 2022.

Filed testimony before the Washington Utilities and Transportation Commission in the Matter of Puget Sound Energy General Rate Case. Docket UE-220066 and Docket-UG220067, January 31, 2022.

Before the Public Service Commission of the District of Columbia, “Pepco’s Climate Solutions 5-Year Action Plan: Benefits and Costs,” report filed on behalf of Pepco in Formal Case No. 1167, January 2022 (with S. Sergici, M. Hagerty, M. Witkin, J. Olszewski, and S. Ganjam).

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 20-170, In the matter of Electric Distribution Utilities Electric Vehicle Time of Use Rates, on behalf of the New Hampshire Department of Energy, October 13, 2021.

Report filed before the Public Service Commission of the District of Columbia, “An Assessment of Electrification Impacts on the Pepco DC System,” on behalf of Pepco in Formal Case No. 1167, August 27, 2021 (with R. Hledik, M. Hagerty, and J. Olszewski)

Testimony before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Application by Nova Scotia Power Incorporated for Approval of Time-Varying Pricing Tariff Application - M09777, May 17, 2021.

Filed rebuttal evidence before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Time-Varying Pricing Tariff Application - M09777, April 22, 2021.

Filed direct evidence before the Nova Scotia Utility and Review Board in the Matter of The Public Utilities Act, R. S. N. S. 1989, c380, as amended and Time-Varying Pricing Tariff Application - M09777, November 30, 2020.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-057, Distribution Service Rate Case, on behalf of the Staff of the New Hampshire Public Utility Commission on rate design studies, December 20, 2019.

Testimony before the State of New Hampshire Public Utilities Commission, Docket No. DE 19-064, Distribution Service Rate Case, on behalf of the Staff of the New Hampshire Public Utility Commission on rate design studies, December 6, 2019.

SELECTED CONSULTING EXPERIENCE

ELECTRIFICATION

- For Consolidate Edison (Con Edison), Brattle is designing the regulatory structure, business model, and rate design for Con Edison's thermal energy network pilots. The pilot projects are testing the efficacy of an inter-building ambient water loop network with geothermal or water source heat pumps in decarbonizing New York's buildings. The Brattle team is assisting ConEd in determining which parts of the infrastructure will be utility owned and operated, developing revenue requirements, and designing a pricing mechanism that will incentivize beneficial customer usage of the network. In addition, the Brattle team is conducting a benefit-cost analysis comparing the thermal energy network to an alternative case of full electrification using air source heat pumps.
- For ERCOT, developed a repeatable process for forecasting electric vehicle load impacts at the substation level out to 2029, for use in their System Planning Assessment and provide an "interactive tool" that could be used to easily replicate and update the analysis in the future. Brattle team developed LDV, MDV, and HDV forecasts for 10 years and allocated these forecasts to the individual substations based on a propensity score model. This model takes into account income, population density and economic activity in a given zip code, and uses this information to allocate forecasted EVs to the substations. After developing EV forecasts for each substation, our team has also developed 8760 charging profiles for all EVs charging at the substation, allowing ERCOT to understand the implications for this new load for transmission planning purposes.
- Development of an Econometric Based EV Forecast for Baltimore Gas and Electric Company. The Brattle Team has compiled a comprehensive repository of national EV adoption related data and estimated an econometric model to explain the drivers of US EV sales, using data from 50 states, from 2011-2019. BGE had expressed a strong preference for a model that relates drivers of EV adoption to sales and did not want to use top down forecasts or a diffusion models

due to their inflexibility to update assumptions. With the econometric model, it was possible to develop various forecasts depending on federal, state and utility incentives; different battery cost trajectories; alternative EV TOU rates; utility owned charging infrastructure among many other drivers. This econometric model was also supplemented by another system-dynamics based module that captured the supply side drivers of EV sales such as increasing model availability, charging infrastructure and improved R&D activities. Brattle team developed alternative EV sales scenarios for BGE's service territory and analyzed the impacts of EV load (under managed and unmanaged scenarios) on utility ratemaking, infrastructure investments and other financial metrics.

- For PGE, led the Brattle team developing EV potential as part of PGE's 2021 DER potential study. Developed light, medium and heavy duty vehicle forecasts through 2040, and quantified the peak, energy and EV charging infrastructure implications of these EV forecasts.
- For Pepco DC, conducted analysis to forecast how the utility's load would increase if aggressive decarbonization goals are met through electrification, and to determine the extent to which energy efficiency and load flexibility measures could mitigate that load growth, highlighting the key role that load flexibility will play in facilitating the decarbonization transition.
- For SRP, developed an updated EV adoption forecast for their territory to inform the potential scale of the managed charging program, analyzed the system-level benefits of managed EV charging to inform the level of customer incentives, including energy and capacity cost savings, and reviewed the design of their pilot study
- For Pepco, assessed the benefits and costs of the company's Climate Solutions Plan. The Plan consists of 62 demand-side initiatives, including large energy efficiency, building electrification, and transportation electrification portfolios. The analysis quantified the energy system and environmental benefits of the programs and evaluated the target scale of the impact of the programs. Led a series of stakeholder workshops on the study findings and methodology. The final report was filed with the DC PSC.
- For Baltimore Gas & Electric, evaluated the benefits and costs of school bus electrification, including the impacts of electric school buses providing vehicle-to-grid (V2G) to the system.
- For Con Edison, Brattle developed a benefit-cost analysis framework as part of New York's Non-Pipeline Alternatives (NPA) initiative. As part of the utility planning process, NPA requires utilities to pursue investments in energy efficiency, clean demand response, and electrification to reduce, defer, or eliminate the need for gas infrastructure investments. The NPA framework evaluates the impact utility supply costs, capital and O&M expenses, customer impacts, GHG emissions, and other associated benefits and costs. Most recently, Brattle has supported Con Edison perform BCA analyses for proposed NPA investments, refine and update assumptions in the model, and implement model improvements based on user feedback.

- For Con Edison, Brattle performed a gas marginal cost of service (MCOS) study to quantify the benefits and costs associated with Con Edison's Non-Pipeline Alternative (NPA) program. The goal was to develop granular MCOS values for different types of gas utility infrastructure within the utility's service territory. The granular MCOS values will allow the utility to quantify the benefit of deferring or avoiding gas infrastructure projects through energy efficiency, clean demand response, electrification, or other NPA-related investments. The study also evaluated how MCOS values evolve in a declining gas demand environment.

GRID MODERNIZATION

- Analyzed the impacts of electric utility infrastructure investment on system reliability and resiliency for a Northeastern Utility, following major weather events. Primary area of analysis involved estimation of economic value of investments to customers using value of lost load (VOLL) metrics for electric system investments.
- Authored a comprehensive report for National Electrical Manufacturer's Association (NEMA) that reviews most recently approved 10 major grid modernization projects. Report discusses business cases and cost recovery mechanisms for each of these projects and documents how grid modernization technologies have benefitted customers and utilities.
- Worked with the Puget Sound Energy Grid Modernization team to identify and quantify the customer-facing use cases enabled by the Company's AML investment. Authored a report detailing the analysis and filed testimony.
- For an investor owned utility, developed a comprehensive survey of cost recovery methods used to recover the costs associated with climate and grid modernization investments, based on the implementations in jurisdictions with major climate goals.
- Served as a member a Technical Advisory Group (TAG), which was formed by Department of Energy (DOE) and Lawrence Berkeley National Laboratory (LBNL). Reviewed and provided feedback on the experimental designs of the utilities that were awarded Smart Grid Investment Grant projects and participated in periodic project review meetings with utilities to review and provide feedback on the interim results as they implement their projects. As part of this assignment, authored a guidance document that discussed different impact evaluation methods, which can be selected by the utilities. This document was shared with the utilities and other TAG members.
- Assisted Pepco Holdings, Inc. to analyze the Phase I of its Conservation Voltage Reduction (CVR) program in its Maryland Service Territory. First of its kind, this econometric study compares consumption of the treatment and control groups before and after the implementation of CVR. More specifically, a regression analysis was conducted to compare the usage levels of treatment

and control group customers to determine whether the CVR treatment resulted in statistically significant conservation and peak demand impacts. The analysis accounts for exogenous factors such as weather, calendar and seasonality impacts as well as utility energy and demand savings programs.

DECARBONIZATION PATHWAYS AND UTILITY PLANNING

- For New Jersey Board of Public Utilities, conducted a comprehensive electric and gas consumer total energy cost impact study to assess the energy burden for customers across several customer classes across all major gas and electric utilities in the state. Estimated the impacts of clean energy policies on different customer segments (e.g. customers adopting electric vehicles vs. customers with a gasoline car). Study identified equity implications, including impacts on low-income consumers and consumers with delayed electrification relative to others. The study can be accessed [here](#).
- For Oracle Utilities, estimated the reduction in greenhouse gas (GHG) emissions that could occur by 2030 and 2050 if customer adoption of GHG-reducing technologies, including energy efficiency, rooftop solar, electric vehicles, and electric heat pumps, rises to an aggressive and achievable level.
- For National Grid Massachusetts, developed an independent assessment of its ESMP that identifies upgrades to the distribution and transmission systems, based on expected future scenarios. Dr. Sergici undertook an in depth assessment of Company's proposed: 1) investments deemed necessary to enable an electrification-based approach to meet State's climate goals ; 2) suite of technology investments, in addition to the more traditional distribution investments targeting capacity deficiencies; 3) suite of technology investments to improve the intelligence and agility of its IT systems, communication networks, and monitoring systems; 4) utilization of NWAs, demand response, TVRs and other load flexibility measures to mitigate load growth.
- For a large Canadian utility, serving as an advisor on the utility's load flexibility assumptions in its integrated resource plan.
- Evaluated how policy reforms could increase access and decrease costs of C&I renewable procurement for the REBA Institute, a group representing commercial and industrial (C&I) customers in the United States, through utility subscription programs, power purchase agreements, and third-party retailer providers. The report finds that there is much potential to increase C&I procurement and costs, but the policy pathway to enable these results is dependent on state characteristics. The report finds that introducing supply choice has the greatest potential to increase access but presents uncertainty regarding costs, and that utility subscription programs can present significant near-term opportunities.

- Assisted the New York City's Mayor's Office of Sustainability to evaluate how a carbon trading scheme would impact the costs and benefits of implementing Local Law 97, an ambitious building-sector decarbonization law that mandates 80% emission reductions by 2050. In collaboration with larger consulting team, Brattle team evaluated building segment data regarding the size and energy use of buildings covered by LL97, reviewing and modeling efficiency and electrification emission abatement retrofits, modeling building owner decision making to comply with the law, and designed a carbon trading policy to ensure the program meets the needs of the city government, environmental justice community, and ultimately lowers societal costs.
- Led the Brattle team that assisted the New York City Mayor's Office of Sustainability with the development of New York City's Roadmap to 80 x 50. The Brattle team analyzed the change in energy-sector greenhouse gas (GHG) emissions resulting from more than six future scenarios. These scenarios explored the impacts of aggressive energy efficiency efforts, off-shore wind, and the continuance of low natural gas prices on the emissions footprint of New York City. The analysis shows that in order to reach 80 x 50, New York City will need to achieve a significant portion of its GHG reductions as a result of a dramatic shift towards a renewables-based grid. This shift towards renewables must overcome the anticipated retirement of nuclear facilities prior to 2050 and will be supported by the implementation of New York State's Clean Energy Standard and the declining cost of renewable energy.
- Conducted a study involving "solar to solar" comparison of equal amounts of residential- and utility-scale PV solar deployed in Xcel Energy Colorado's Service Area. Calculated costs and benefits of each of these two different but equally sized solar options, i.e., avoided energy, capacity and distribution network costs and others. The study found carbon reductions were greater on utility scale systems because the solar energy per MW is much higher on utility-scale due to better placement and tracking capability.
- Assisted the Southern Company IRP team to explore the impacts of modeling energy efficiency on the demand side (involves screening each EE measure for cost-effectiveness outside of the resource planning model) versus on the supply-side (each EE measure is represented as part of an EE supply curve, which directly competes with generation resources in the model's capacity planning decision algorithm)
- Advised Nova Scotia Power Inc. on the reasonableness of the DSM scenarios and strategies that are being modeled in their Integrated Resource Plan (IRP). This effort also involved advising the Company on a variety of DSM issues and building up a model that quantifies the rate impacts for program participants and non-participants based on the selected DSM scenario.
- Coauthored the State's Annual Integrated Resource Plan (IRP) for the Connecticut Department of Energy and Environmental Protection (DEEP). This effort involved development of scenarios

and strategies for an electric system to meet long-range electric demand while considering the growth of renewable energy, energy efficiency, other demand-side resources. Led the development of demand side management and emerging technology resource strategies and analyses involving these resources.

- Developed a model to assess the prudence of an electric utility's power procurement strategy in comparison to several other alternative options. As a result of this model, she assessed whether it is prudent to recover the congestion and loss costs associated with utility's chosen strategy from ratepayers in a state regulatory proceeding.
- Assisted in preparation of a marginal cost study for an integrated electric utility. The study estimated the incremental costs to the utility of serving additional demand and customer by time period, sub-region, and customer class. The costs were identified as energy, capacity and customer related for generation, transmission, and distribution systems of the utility.
- Assisted in developing an integrated resource plan for major electric utilities. Contributed to the design of future scenarios against which the resource solutions were evaluated. Designed scenarios were driven by external factors including fuel prices, load growth, generation technology capital costs, and changes in environmental regulations. Forecasted the inputs series for the resource planning model consistent with each of the designed scenarios.

DISTRIBUTED ENERGY RESOURCES

- For a U.S. utility, reviewed the utility's benefit cost assessment model used to evaluate distributed energy resources for alignment with commission orders and staff guidance. The assessment identified areas for refinement, including increasing the temporal and geographic granularity of the model. As part of the review, the Brattle team provided insights into potential misalignments between the valuation of transmission and distribution investment deferral within the model, customer value, and system value. The Brattle team rebuilt the model from the ground-up to allow for intuitive use and ensure that assumptions are clearly articulated and well-documented.
- For a DER software developer, estimated the potential market value of residential load flexibility offerings across five utilities. The analysis highlighted that the load flexibility value proposition varies significantly depending on system and market conditions. The final report is a key input to the company's load flexibility business case.
- For a large east-coast utility, reviewed benefit cost framework and model data to evaluate non-pipeline alternatives. The review included treatment of geographic differences in marginal costs due to pipeline access, and the Brattle team rebuilt the model from the ground-up to allow for intuitive use.

- For a large east-coast utility, developed a benefit-cost analysis model to screen non-wires alternative projects.
- System Dynamics Modeling of DER Adoption and Utility Business Impacts. Led the development of Brattle’s Corporate Risk Integrated Strategy Platform (CRISP) model and assisted utility clients with the implementation of this model. CRISP is based on System Dynamics approach, which creates simulations based on dynamic feedbacks between utility policies and customer behavior, providing a new perspective on how much and how fast the “utility of the future” must evolve. The focus of these modeling efforts was to help utilities anticipate and accommodate distributed energy resources (DERs) as they become more economical and more widely adapted by retail electricity customers, and to evaluate the sustainability of their traditional cost-of-service business model in the face of such trends.
- For EPRI, conducted a study to explore methods for incorporating DERs into integrated resource planning. A unique feature of this study was the use of Brattle’s capacity expansion model, GridSIM, to quantitatively illustrate the implications of various DER modeling techniques. In the first phases of the engagement, we assessed the implications of different approaches to modeling energy efficiency (EE) and demand response (DR), such as the advantages and disadvantages of modeling these resources on the “supply side” versus the “demand side” of the model. The current phase of the project focuses on electric vehicles (EVs) and rooftop solar, and includes a review of techniques for forecasting adoption of these technologies, as well as modeling the resource impacts of growth in EV adoption.
- Estimated NEM cross-subsidies using data from sixteen utilities. Used cost-of-service methodology to compare NEM customers costs on the system vs. revenue collection from these customers using company COS studies, and supplementing it by publicly available data on solar PV production profiles, installed DG capacity by utility and system load profiles.

INNOVATIVE RATE DESIGN AND IMPACT EVALUATION STUDIES

- For Interstate Power and Light, Dr. Sergici reviewed IPL’s tariffs; proposed updates to the existing rates and designed several optional rates for IPL’s residential and non-residential customers. Brattle team updated IPL’s embedded cost of service study, developed a marginal cost of service study and designed two default and four optional rates. Dr. Sergici filed direct testimony detailing methodologies for these studies and rate designs.
- For a gas and electric distribution utility in the Northeast, analyzed the operating cost of electric heat pumps and natural gas-fueled heating equipment, quantified the cost gap between the two types of equipment under alternative rate designs, and assisted in the development of rate designs to mitigate the cost gap. The study included estimation of the electric load impacts of electrification of a small sample of the utility’s residential customers based on their historical

gas usage, followed by calculation of their hypothetical future electricity bills under various rate structures. The utility is using insights from this study to appropriately size heat pump incentives and to mitigate the heat pump affordability barrier by marketing a beneficial rate structure to customers.

- Assisted with rate design proposal. Brattle has been retained by Nova Scotia power to assist with a comprehensive evaluation of innovative rate designs and development of Company's rate design proposal including load and bill impact analyses. Brattle team participated in stakeholder sessions to socialize the rate design with the stakeholders.
- Review of Rate Design Studies on Behalf of the Staff of the New Hampshire Public Utilities Commission. Brattle reviewed the rate design studies presented by Liberty Utilities and Eversource and filed testimony on behalf of the Staff. Both studies focused on the distribution services offered by the utilities and examined and testified on issues involving embedded and marginal cost based rate design. Dr. Sergici filed direct testimony in the proceeding.
- For CPS energy, prepared educational presentation materials for Rate Advisory Committee meetings. Prepared slide decks to explain concepts and methods in cost of service and rate design studies; summarized results from previous Brattle projects.
- Design, measurement and verification of Maryland Joint Utilities' PC44 TOU pilot. Brattle serves as the technical lead on behalf of the Maryland Joint Utilities, and led the pilot design and M&V methodology work streams in the PC44 workgroup process. Brattle will evaluate results from these three pilots in 2020.
- Assisted a New Zealand distribution utility with development of a peak time rebate pilot. Advised the client in pilot design principles and calculated sample sizes to yield statistically significant results. Undertook empirical testing of more than 150 different baseline methods using the client data and recommended an approach that leads to the highest accuracy and lowest bias in predicting the event day usage.
- Developed a model for the Ontario Energy Board to estimate a counterfactual hourly customer demand profile for multiple innovative pricing profiles of interest. Evaluated the economic efficiency of each alternative pricing option, taking into account system cost drivers including energy, ancillary services, generation capacity, and transmission and distribution capacity, as well as overall changes to consumer welfare driven by induced changes in demand. This represents one of few efforts to fully quantify the societal costs and benefits of innovative rate structures and involved close collaboration with the OEB team to ensure the Ontario-specific market structures were accurately reflected in our analysis.
- Technical Advisor to OEB on the New RPP Pilots. A Brattle team led by Dr. Sergici has developed a Technical Manual to guide the design and impact evaluation of new RPP pilots. Dr. Sergici has

been closely working with the OEB RPP team as they oversee the implementation of these pilots in accordance with the guidelines

- Undertook impact Evaluation of Ontario's Time-of-Use Rates on Behalf of Ontario Power Authority. A Brattle team led by Dr. Sergici provided an impact evaluation of Ontario's province-wide roll-out of Time-of-Use (TOU) rates for its residential and general service customers on behalf of Ontario Power Authority. Brattle acquired hourly load data from the IESO and the LDCs, aggregated it for the pricing periods that correspond to the TOU rate, reinterpreted the full-scale deployment as a natural experiment, and analyzed it using econometric methods for three consecutive years.
- Undertook a retail rate benchmarking study for a large southwestern utility. Our team, led by Dr. Sergici, reviewed utility resource plans to estimate each utility's retail rate trajectory. We compared the utilities across a variety of rate drivers, such as reserve margin, fuel mix, load growth, load factor, renewables investment requirements, and demand-side activities, and provided strategic recommendations for addressing these drivers of future rate growth.
- Undertook an extensive review of the rate designs and methodologies used by other jurisdictions/countries for a large Canadian Utility. We reviewed the rates that are currently offered by a large Canadian utility and compared them with best industry practices from around the globe. As a result of our analysis, we identify some near term and long term alternative rate design options for our client, which can help them to manage revenue risks and volatility due to the effects of disruptive threats, and at the same time to increase innovation and affordability in the rate options presented to the customers.
- Assisted Pepco Holdings, Inc. to evaluate the effectiveness of the AMI-enabled energy managements tools (EMTs) in reducing per capita energy use. Led a team of four researchers to compile and process data for four of the PHI jurisdictions; identify relevant control groups and methodology for impact evaluation and undertake an econometric analysis to quantify the EMT impact.
- Assisted an industry-leading provider of integrated demand response, energy efficiency, and customer engagement solutions in the design of and M&V plan for a behavioral demand response program. The plan included a detailed section on sampling selection for statistically valid and detectable program impact results.
- Prepared a comprehensive blueprint document for measuring the impacts of Baltimore Gas and Electric Company's Smart Grid Customer Programs. BGE has started deploying smart meters to all of its residential customers in Spring of 2012 and is scheduled to complete the deployment over a three-year period. BGE developed a full-scale program, "Smart Energy Manager (SEM)" program, to meet a central objective of the Smart Grid Initiative - customer education and engagement in a Smart Grid environment. The blueprint documented the design elements of

the SEM program and introducing the approaches that will be used to measure the impacts of different SEM tools once the program is in the field and sufficient data are collected.

- Measurement and evaluation for in-home displays, home energy controllers, smart appliances and alternative rates for FPL. Carried out a 2-year impact evaluation of a dynamic and enabling technology pilot program. Used econometric methods to estimate the changes in load shapes, changes in peak demand, and changes in energy consumption for three different treatments. The results of this study were shared with Department of Energy as to fulfill the data reporting requirements of FPL's Smart Grid Investment Grant.
- Pricing and technology pilot design and interim impact evaluation for Commonwealth Edison Company (ComEd). Assisted ComEd in the design of an ambitious pilot program that included approximately 25 different treatment cells. The pilot, which is the first "opt-out" pilot program of its kind, involved 8,000 customers and tested the impact of dynamic prices with and without customer education, informational feedback through basic and advanced feedback devices, and other enabling technologies in the summer of 2010. Conducted an interim impact evaluation study preceding the formal impact evaluation of the study, which is planned to be completed by the end of 2011.
- Pricing and technology pilot design and impact evaluation for Consumers Energy. Designed Consumers Energy's pricing and technology pilot and conducted the impact evaluation study after the pilot was completed in September 2010. The pilot tested critical peak pricing (CPP) and peak time rebates (PTR) in conjunction with information treatment and technology. The pilot also tested the potential "Hawthorne bias" for a group of control group customers who were aware of their involvement in the pilot.
- For an Independent System Operator (ISO), designed, managed and analyzed a market research to help improve participation in retail electricity products that encourage price-responsive demand (PRD). The research determined customer preferences for various time-based pricing products that would help define PRD products that may be developed in the ISO for each customer class. ISO will use the results of this research to assist in modifying wholesale market design to better support such PRD products.
- Assisted a client in conceptually developing a new product that would increase customer participation and performance in energy efficiency (EE) and demand response (DR) programs. Developed Total Resource Cost (TRC) tests for a few targeted EE and DR programs, and modeled the benefits and costs with and without the client's new product offering
- Co-authored a whitepaper reviewing the results from five recent pilot and full-scale programs that investigated low-income customer price-responsiveness to dynamic prices. The core finding of the whitepaper is that low income customers are responsive to dynamic rates and that many such customers can benefit even without shifting load.

- For a large California utility, conducted an econometric analysis, which investigated the role of weather conditions, smart meter installations, and electricity rate increases, among other control variables, in explaining the changes in the monthly usages and bills of a group of complaining customers. Estimated pooled regressions using a panel dataset, as well as individual customer regressions for more than 1,000 customers.
- Assisted an Illinois electric utility in the assessment of alternative baseline calculation for implementing peak time rebate (PTR) programs. Under a PTR program, participants receive a cash rebate for each kWh of load that they reduce below their baseline usage during the event hours. This requires establishment of a baseline load from which the reductions can be computed. The analysis involved simulating baselines for more than 2,000 customers using five alternative methodologies for several event days. Identified and recommended the baseline calculation methodology that yielded the most accurate baseline for individual customers, through the use of MAPE and RMSE statistics.
- Evaluated the Plan-It Wise Energy program (PWE) of Connecticut Light and Power (CL&P) Company. PWE tested the impacts of critical peak pricing (CPP), peak time rebates (PTR), and time of use (TOU) rates on the consumption behaviors of residential and small commercial customers. Each rate design was tested with high and low price variation as well as with and without enabling technologies. Conducted an econometric analysis to determine weather dependent substitution and daily price elasticities and subsequently quantified demand and energy impacts for each of the treatments tested in the PWE. Developed optimal rate designs to be adopted in a full deployment scenario.
- For Baltimore Gas and Electric Company, assisted in the preparation of direct and rebuttal expert testimonies before the Maryland Public Service Commission, that explain the design and results of 2008 and 2009 Smart Energy Pricing (SEP) pilots.
- Evaluated the Smart Energy Pricing (SEP) pilot program of Baltimore Gas and Electric Company for three consecutive years. The pilot was designed to quantify the impacts of critical peak pricing (CPP) and peak time rebates (PTR) on residential customer consumption patterns. Conducted an econometric analysis to estimate demand systems and predict substitution and daily price elasticities for participating customers. Using the parameters of the demand equations, quantified demand, energy, and bill impacts associated with the programs. Impacts of the socio-demographic characteristics of the participants as well as their ownership of enabling technologies were separately identified on the demand response of the program participants.
- Co-authored a business practice manual for forecasting price responsive demand (PRD) in Midwest ISO. The draft manual introduces different methodologies for measuring and incorporating PRD into forecast LSE requirement for LSEs that are at different stages of rolling-

out their out their dynamic pricing programs. The draft manual also proposes methodologies for the verification of the forecasted demand net of PRD for long term planning purposes.

- Assisted in the development of an affidavit that evaluates the implications of PJM's proposed revisions to the Operating Agreement (OA) on barriers to participation in PJM's Economic and Emergency Load Response programs.
- Co-authored a whitepaper on "Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets" for Institute for Electric Efficiency. Whitepaper is intended to help facilitate nationwide progress toward the deployment of dynamic pricing of electricity by summarizing information that may assist utilities and regulators who are assessing the business case for advanced metering infrastructure (AMI).
- Assisted a New York utility in benchmarking their existing Demand Response (DR) portfolio to the best practice in U.S. and recommended improvements in their planned DR portfolio. Also assisted the utility in quantifying costs and benefits of pilot programs proposed in their DR filing before the State of New York Public Service Commission.
- Assisted an electric utility in developing a residential pricing pilot program that tests inclining-block rate (IBR) structure. More specifically, designed several revenue neutral IBR alternatives and quantified load reduction and bill impacts from these IBR rates.
- Assisted an electric utility in their dynamic rate design efforts. Conducted impact analyses of converting from a flat rate design to alternative dynamic rate designs for each of the five major customer rate classes of the utility. Developed models that allow simulation of energy, demand, and bill impacts by season, day type and time period for an average customer from each of customer classes.
- Simulated the potential demand response of an Illinois utility's residential customers enrolled in real time prices. Results of this simulation were used in recent Midwest ISO Supply Adequacy Working Group (SAWG) meeting to facilitate conversation about price responsive demand in the region. Simulations were run for different scenarios including historic versus spiky real-time prices; peak versus uniform allocation of capacity charges; and with and without enabling technologies.
- Designed a survey on Long-run Drivers of U.S. Energy Efficiency and Demand Response Potential on behalf of EPRI and EEI. Conducted statistical analyses to examine the survey responses, which were turned in by more than 300 power industry leaders and academic experts. Using the outcomes from this survey, assisted in the development of future scenarios to model energy efficiency and demand response impact through 2030.
- Assisted in the preparation of an EEI report that quantifies the benefits to consumers and utilities of dynamic pricing. Undertook a comprehensive review of the dynamic pricing programs

across the U.S. and elsewhere. Also implemented price response simulations to quantify the likely peak demand reductions that would realize under alternative dynamic pricing schemes.

UTILITY REGULATORY AND BUSINESS MODELS

- Assisted the New York Department of Public Service to develop a comprehensive financial model of a representative (downstate) New York utility capable of demonstrating the impacts of REV initiatives upon utility financial performance. Our modeling effort included developing plausible incentive regulation frameworks, new incentive mechanisms, and potential platform frameworks, services and futures.
- Development of Performance Incentive Metrics for the Joint Utilities of New York. The Brattle Group worked with the New York PSC Staff and, subsequently, with the State's six investor owned electric utilities (Joint Utilities) in analyzing the feasibility and impacts associated with proposed earnings sharing mechanisms (EAMs), primarily the EAMs associated with load factor and system efficiency.
- Assisted a North American Utility with development of a short-term and long-term regulatory strategy to enable their 2030 Vision. Brattle team interviewed the executive team; identified consensus views and disagreements on alternative business models and regulatory models. Developed straw proposals for two potential regulatory models one focused on enabling shorter-term outcomes, and the other focused on enabling Company's longer-term vision.
- Assisted Pepco D.C. as they develop a multi-year rate plan and various traditional and emerging performance incentive metrics to be filed in their upcoming rate case. Brattle team developed and facilitated workshops to introduce Pepco's MYRP proposal to the stakeholders and assisted Pepco with incorporating stakeholder input to the final proposal.
- Assisted a Canadian Utility with a critical assessment of their custom incentive ratemaking model and discussed how it compares with other forms of PBR. We presented a jurisdictional scan of the PBR implementations across North America and Europe, and assessed pros and cons of each approach. We also advised them on currently proposed "Distributed Utility Models" and assess pros and cons of each model; reviewed "Alternative Regulatory Models" that were developed to ensure that utilities can coexist with the DERs and continue to maintain healthy balance sheets.
- For a Canadian electric utility, reviewed and summarized alternative regulatory frameworks and incentive models that would support a sustainable energy efficiency business. Investigated the pros and cons of these models, identified the implications of each model for the utility, and made a recommendation based on our findings. Utility will discuss the recommended approach with the regulator and seek an approval.

- For a large Canadian electric utility, assisted with the development of an alternative proposal to their current performance based regulation (PBR) framework. Examined and benchmarked several examples of performance based regulation schemes in place for other utilities, and advised on an enhanced PBR mechanism.

DEMAND FORECASTING

- For National Grid Massachusetts, reviewed Company's spatial load forecasting methodology which involves econometric models and incorporates a feeder level DER allocation method. Dr. Sergici provided an expert opinion as part of the Company's ESMP filing.
- For an Asian utility considering an investment on a generation plant in PJM, we have reviewed, replicated, and developed alternative load forecasts using PJM's 2017 update. We have determined several uncertainty factors that are not fully captured in PJM's forecasting framework and developed "low load" and "high load" scenarios after accounting for these factors.
- For an electric utility in the Southeast, reviewed load forecasting models for residential and commercial customer classes. Assessed the accuracy and validity of the models by reviewing the historic and forecast period inputs to the model; model specification; in-sample and out-of-sample accuracy statistics; and incorporation of DSM impacts to the model, among many others. Also conducted an analysis using the U.S. Energy Information Administration's Annual Energy Outlook (AEO) data to determine the forecast errors during pre and post-recession periods.
- Developed a blueprint for integrating energy efficiency program impacts into the load forecasts for a Canadian Utility. This effort involved estimating the future impact of energy efficiency programs to be included in the load forecasts and developing price elasticity estimates that can be used to forecast the impact of the future changes in the price of electricity.
- Developed a load forecasting model for the pumping load of California State Water Project. Identified the main drivers of pumping load in major pumping stations. Through Monte Carlo simulations, quantified the uncertainty around load forecasts.
- Assisted in the preparation of testimony that evaluates the reasonableness of Florida Power and Light Co.'s total customer and monthly net energy for load (NEL) forecasting models. In addition to evaluating the methodology, also reviewed the reasonableness of the inputs used in the historic and forecast periods and assessed the soundness of ex-post adjustments made to the forecasts.
- Assisted PJM in the evaluation of its models for forecasting peak demand and re-estimated new models to validate recommendations. Predicted forecasting errors of the existing models and helped improving the forecast methodology by introducing the state-of-the art estimation

techniques. Individual models were developed for 18 transmission zones as well as a model for the entire PJM system.

- Assisted a large utility in New York in understanding the decline in electric sales during the recent past and attributed the decline to a change in customer expectations of future income, based on declining consumer confidence that has been created by the lingering economic recession.
- Reviewed the structure of the Tennessee Valley Authority's energy sales forecasting models by sector, assessed the magnitudes of the price elasticities and the model specifications used to generate them, analyzed the ability of the models to generate a baseline forecast that could serve as a point of reference when evaluating the likely impacts and cost-effectiveness of a wide range of new energy efficiency and demand response programs.
- Developed a demand forecast model for one of the world's largest steam system operators. Estimated regression models to predict the price elasticities and switching behavior of different consumer classes. Also helped in the development of a model to forecast the impact of alternative steam tariffs on the consumption and switching patterns of consumers.

SELECTED WHITEPAPERS AND REPORTS

- *Do Customers Respond to Time-Varying Rates: A Preview of Arcturus 3.0*, with Ahmad Faruqui, and Sylvia Tang, (January 31, 2023)
- *Heat Pump-Friendly Cost-Based Rate Designs*, with Goksin Kavlak, Akhilesh Ramakrishnan, Megan Diehl, and Adam Bigelow, prepared for Energy Systems Integration Group (ESIG), (January 30, 2023)
- *ERCOT EV Allocation Study: Methodology for Determining EV Load Impact at the Substation Level*, with Goksin Kavlak, Michael Hagerty, Julia Olszewski, and Grace Kortum, prepared for ERCOT, (October 13, 2022)
- *Community Solar Value Stack in Arizona*, with Akhilesh Ramakrishnan, Michael Hagerty, Beste Kaygisiz, Megan Diehl, and Xander Bartone, prepared for Cypress Creek Renewables, (August 30, 2023)
- *New Jersey Energy Master Plan Ratepayer Impact Study*, with Goksin Kavlak, Kathleen Spees, Rohan Janakiraman, prepared for New Jersey Board of Public Utilities, (August 23, 2022)
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- “Piloting the Smart Grid,” with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal* (August/September 2009)
- “The Impact of Informational Feedback on Energy Consumption - A Survey of the Experimental Evidence,” with Ahmad Faruqui and Ahmed Sharif, *Energy-The International Journal* (August 2009)
- “Three Essays on U.S. Electricity Restructuring,” Unpublished Ph.D. Thesis, Northeastern University (August 2008)

PRESENTATIONS & SPEAKING ENGAGEMENTS

- “Emerging Technologies and Tools for the Future,” presentation at the 8th Annual Grid Modernization Forum (June 2023)
- “Electricity Retail Rates to Facilitate Electrification,” presentation at the MIT Future Energy Systems Center Spring 2023 Workshop (June 2023)
- “Developing Innovative Rates for Accelerating the EV Transition,” presentation for the DOE EVGrid Assist Team (January 2023)
- “Heat-pump Friendly Cost-Based Rate Designs,” presentation at the 2022 NARUC Meeting (November 2022)
- “High Priority Areas for Accelerating EV Transition, “ presentation at the 2022 NARUC Meeting (November 2022)
- “Modernizing the Grid,” presented at the MIT Energy Conference (March 2022)
- “Designing Effective EV Managed Charging Programs,” presented at the Peak Load Management Association (PLMA) webinar (October 28, 2021)
- “A New Approach to Strategic Planning in a High Distributed Resource Environment: Distributed Solar as a Case Study,” Next-Gen Smart Grid Virtual Summit (December 9, 2020)
- “What Explains the Success of Top Performing States in Energy Efficiency?” NRRI Webinar (August 19, 2020)
- “A Blueprint to Pilot Design: Best Practices and Lessons Learned,” MI Power Grid: Energy Programs and Technology Pilots Stakeholder Meeting (April 30, 2020)
- “Policies in Support of Customers’ Purchase of Renewable Energy,” NARUC Annual Meeting & Education Conference (November 18, 2019)

- “Rate Reform in Evolving Energy Marketplace,” EUCI Residential Demand Charges/TOU Summit (May 30, 2019)
- “Grid Modernization: Policy, Market Trends and Directions Forward,” 4th Annual Grid Modernization Forum, Chicago, IL (May 21, 2019)
- “Accelerating the Renewable Energy Transformation: Role of Green Power Tariffs and Blockchain,” EUCI Southeast Clean Power Summit (February 25, 2019)
- “The Case for Alternative Regulation and Unintended Consequences of Net Energy Metering,” 46th Annual PURC Conference, Gainesville, FL (February 21, 2019)
- “Reviewing Grid Modernization Investments: Summary of Recent Methods and Projects,” National Electrical Manufacturers Association (NEMA) (December 4, 2018)
- “Enabling Grid Modernization Through Alternative Rates and Alternative Regulation,” Energy Policy Roundtable in the PJM Footprint (November 29, 2018)
- “Return of Pay-for-Performance Stronger with M&V 2.0,” BECC Conference, Innovations in Models, Metrics, and Customer Choice, Washington DC (October 2018)
- “Rate Design in a High DER Environment,” MEDSIS Rate Design Workshop, Washington DC, (September 2018)
- “Demand Response for Natural Gas Distribution,” Center for Research in Regulated Industries (CRRRI) 31st Annual Western Conference, Monterey CA (June 2018)
- “Status of Restructuring: Wholesale and Retail Markets,” National Conference of State Legislatures Workshop, “Electricity Markets and State Challenges,” Indianapolis IN (June 2018)
- “Dynamic Pricing Works in a Hot and Humid Climate: Evidence from Florida,” International Energy Policy & Programme Evaluation Conference, Bangkok Thailand (November 2017)
- “Understanding Residential Customer Response to Demand Charges: Present and Future,” EUCI Residential Demand Charges Conference, Chicago IL (October 2016)
- “Utility Leaders Workshop: An Evolving Utility Business Model for the Caribbean,” Caribbean Renewable Energy Forum, Miami FL (October 2016)
- “Impact of Residential PV Penetration on Load Growth Expectations,” AEIC Western Load Research Conference, September 2016.
- “Moving away from Flat Rates,” Smart Grid Consumer Collaborative, Chicago, IL (September 2016)

- “Residential Demand Charges: An Overview,” EUCI Demand Charge Conference, Phoenix AZ (June 2016)
- “Conservation Voltage Reduction Econometric Impact Analysis,” AESP Spring Conference, Washington DC (May 2016)
- “Caribbean Utility 2.0 Workshop- Economics, Tariffs and Implementation: The Challenge of Integrating Renewable Resources and After Engineering Solutions,” co-hosted and presented at the Caribbean Renewable Energy Forum, Miami FL (October 2015)
- “Dispelling Common Residential DR Myths,” eSource Conference (October 2015)
- “Low Income Customers and Time Varying Pricing: Issues, Concerns, and Opportunities,” NYU School Law’s Forum on New York REV and the Role of Time Varying Pricing (March 2015)
- “Dynamic Pricing: Transitioning from Experiments to Full Scale Deployments,” EDF Demand Response Workshop, Paris, France (July 2014) and Governors Association’s Michigan Retreat on Peak Shaving to Reduce Wasted Energy (August 2014)
- “Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada,” 2014 Smart Grid Virtual Summit, Boston (June 2014)
- “Residential Demand Response Opportunities,” Opower Webinar Series, Boston (June 2014)
- “Impact Evaluation of TOU Rates when Experimentation is not Option: A Case Study of Ontario, Canada,” 33rd Annual Eastern CRRI Conference (May 2014)
- “The Arc of Price Responsiveness—Consistency of Results Across Time-Varying Pricing Studies,” Chartwell Webinar, Boston (May 2013)
- “Evaluation of Baltimore Gas and Electric Company’s Smart Energy Pricing Program,” 9th International Industrial Organization Conference, Boston, MA (April 2011)
- “Dynamic Pricing: What Have We Learned?” Electricity Markets Initiative Conference, Harrisburg, PA (April 2011)
- “Do Smart Rates Short Change Customers,” Demand Resource Coordinating Committee Webinar (December 2010)
- “Opening Remarks and Session Chair of Day 1,” FRA Conference on Customer Engagement in a Smart Grid World, San Francisco, CA (December 2010)
- “The Impact of Informational Feedback on Energy Consumption,” 2010 National Town Meeting on Demand Response and Smart Grid (June 2010)

- “The Impact of In-Home Displays on Energy Consumption,” Colorado Public Service Commission (June 2010)
- “Does Dynamic Pricing Work in the Mid-Atlantic Region: Econometric Analysis of Experimental Data,” Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference (May 2010)
- “Distributed Generation in a Smart Grid Environment,” panel speaker at the Center for Research in Regulated Industries (CRRI) 29th Annual Eastern Conference (May 2010)
- “Power of Information Feedback: A Survey of Experimental Evidence,” Peak Load Management Alliance (PLMA) Webinar (April 2010)
- “Customer Response to Dynamic Pricing - A Long Term Vision,” 2009 NASUCA Mid- Year Meeting, Boston (June 2009)
- “BGE’s Smart Energy Pricing Pilot Summer 2008 Impact Evaluation,” Association of Edison Illuminating Companies (AEIC) Conference, Florida (May 2009)
- “California and Maryland - Are They Poles Apart?,” Western Load Research Association Conference, Atlanta (March 2009)
- “Experimental Design Considerations in Evaluating the Smart Grid,” Smart Grid Information Session Massachusetts DPU (December 2008)
- “Divestiture, Vertical Integration, and Efficiency: An Exploratory Analysis of Electric Power Distribution,” 4th International Industrial Organization Conference, Boston, Massachusetts (2006)

AFFIRMATION

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

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



Date: May 31, 2024

SANEM SERGICI

SNULLER PRICE

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 _____

Prepared Direct Testimony of

Snuller Price

SECTION I: INTRODUCTION

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

A. My name is Snuller Price, and I am a Senior Partner at Energy and Environmental
Economics (“E3”). My business address is 44 Montgomery Street, Suite #1500,
San Francisco, California, 94104. I am filing testimony on behalf of Nevada Power
Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company
d/b/a NV Energy (“Sierra” and, together with Nevada Power, “NV Energy”).

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

A. I have been working in the utility industry since 1993 as a consultant at E3. Prior
to joining E3, I received a B.A. in Economics from Swarthmore College, and a B.S.
in Engineering from Swarthmore College. While employed at E3, I received an
M.S. from Stanford University in Engineering Economic Systems and Operations
Research in 1998.

While at E3, I have worked on projects for many electric utilities, utility
commissions, state energy offices, and the federal government (Environmental

Protection Agency and Department of Energy). A majority of these projects have focused on distributed energy resource (“DER”) evaluation. This includes energy efficiency (“EE”) cost-effectiveness, developing avoided ratepayer costs, evaluation of the cost-effectiveness of numerous other types of DERs including demand response (“DR”), rooftop solar, distributed battery storage, and other technologies for flexible load (e.g., smart thermostats, smart panels, and smart vehicle charging). I have also evaluated the integration of DERs into distribution planning as non-wires alternatives (“NWAs”) to traditional wired capital upgrade solutions.

In addition to my work on DERs, I have completed numerous projects for utilities, utility commissions, and state energy offices on reducing greenhouse gas emissions through electrification (that is, switching fossil-fuel end-uses to use electricity to reduce greenhouse gas emissions). I was also a co-author of a 2012 publication in *Science* titled “The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity.”

My statement of qualifications is attached as **Exhibit Price-Direct-1 – Statement of Qualifications**.

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

A. I am an industry consultant working entirely on utility industry analyses, generally leading analysis teams in topics related to DERs and electrification.

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

4 A. No.
5

6 5. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY
7 IN THIS CASE?

8 A. My testimony is in support of the DER evaluation framework, tools, and scenarios
9 that were used to develop NV Energy’s Market Potential Study (“MPS”) and
10 describes the new capabilities, tools, metrics, and approach in the DER evaluation
11 framework to inform the Commission and stakeholders on the new approach and
12 potential uses. I also support the specific analysis and results of the equipment
13 stock roll-over that is a key input to develop the technical potential in the MPS.
14

15 Additionally, I support the following Technical Appendices:

- 16 • Technical Appendix DRP-5 associated with the Distributed Resources Plan
17 (“DRP”) narrative, which explains E3’s methodology and approach in using
18 its Forecasting Anywhere model;
- 19 • Technical Appendix DRP-6 associated with the DRP narrative, which
20 provides the DER results of the PATHWAYS model; and
- 21 • Technical Appendix DSM-26 associated with the Demand Side
22 Management (“DSM”) Plan narrative, which is the MPS Report.
23
24
25
26
27

6. Q. ARE OTHER NV ENERGY WITNESSES SUPPORTING OTHER ASPECTS OF THE MPS?

A. Yes. The remaining aspects of the analyses in the MPS are supported by two additional witnesses:

- Mr. Kenneth Skinner of Integral Analytics (“IA”) is the witness on the cost-effectiveness analysis completed with DSMore; and
- Mr. Tom Hines of Tierra Resource Consultants is the witness on developing Realistically Achievable EE and DR Savings Potential.

7. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?

A. I am sponsoring **Exhibit Price-Direct-1 – Statement of Qualifications**.

8. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized in four sections:

- Section I: Introduction;
- Section II: Overall modeling framework and potential uses;
- Section III: Model descriptions and reasons for their use; and
- Section IV: Scenarios considered and relevant outputs.

SECTION II: OVERALL MODELING FRAMEWORK AND POTENTIAL USES

9. Q. PLEASE BRIEFLY DESCRIBE THE DER EVALUATION FRAMEWORK USED IN THE MPS.

A. The DER evaluation framework begins by developing technical potential, and then proceeds through a series of analyses to estimate economic potential, maximum achievable potential, and realistically achievable potential. This is the same basic approach many utilities use in their market potential studies. However, NV Energy,

1 IA, E3, and Tierra introduce a new framework to include additional capabilities
2 into this process.

3
4 **10. Q. WHY INTRODUCE A NEW DER EVALUATION FRAMEWORK?**

5 A. The DER evaluation framework introduced in the MPS was developed to provide
6 an expanded set of capabilities to:

- 7 (1) better coordinate across utility planning (Demand Side Management,
8 Integrated Resource Planning, Distribution Planning, and Integrated Grid
9 Planning);
10 (2) explore a broader set of scenarios that can include state and federal policy
11 actions including decarbonization and clean energy goals; and
12 (3) improve the evaluation of different types of DERs with a broader set of
13 portfolio metrics.

14
15 **11. Q. WHAT WAS YOUR APPROACH TO USING THE NEW DER**
16 **EVALUATION FRAMEWORK?**

17 A. I would describe our approach as “walk, jog, run,” similar to the approach that NV
18 Energy already employs in its DRP. NV Energy and E3 introduced a new toolkit
19 with significantly enhanced capability, and it is being used to make modest
20 adjustments relative to prior NV Energy market potential studies. This approach
21 has the advantages of allowing the team to present an MPS that can be compared
22 to prior study results, to share the framework with stakeholders before it is relied
23 on in future analyses, to gain experience by implementing the process in the MPS
24 before adding more complexity, and to build a foundation for future analyses that
25 do incorporate additional capabilities.

12. Q. **WHAT NEW TOOLS AND CAPABILITIES ARE BEING ADDED IN THE NEW DER EVALUATION FRAMEWORK?**

A. The first new tool introduced was PATHWAYS, which is E3’s economy-wide greenhouse gas (“GHG”) and energy demand accounting and stock rollover model. This tool allows NV Energy to consider a broad range of future scenarios driven by different potential policy futures. Each of the six scenarios and their results are described in the MPS Report. The “Mid Scenario” was used for the purposes of developing the MPS results, which reflects existing policy through 2030. This is consistent with the “walk, jog, run” approach. Future analyses could also consider other scenarios that integrate, for example, much higher electric vehicle (“EV”) adoption (due to the federal Corporate Average Fuel Economy (“CAFE”) standards) or other policies that affect stock roll-over and therefore technical potential.

The second new tool is the E3 and IA Forecasting Anywhere tool that performs a granular geospatial allocation of DER adoption in the PATHWAYS scenarios based on customer demographics, building and parcel data, and a variety of other data sources. This geospatial allocation of DER adoption can be mapped onto NV Energy’s electric distribution system to inform its DRP and to quantify impacts in Low- and Moderate-Income (“LMI”) communities. Forecasting Anywhere itself is an interim step towards the deployment of the more sophisticated LoadSEER software underway at NV Energy which provides similar geospatial load results and overlays those loads with the existing electric distribution system topology for a potentially broad range of distribution system analyses. As an early application of Forecasting Anywhere, NV Energy used a portion of the Mid Scenario geospatial DER adoption output in the NWA analyses in its 2024 DRP.

The third new tool in the DER evaluation framework is DSMore, which is a DER cost-effectiveness evaluation tool developed by IA. Moving forward, NV Energy will seek to use DSMore to replace AceGuru, which has been used in prior cost-effectiveness analyses. DSMore allows the cost-effectiveness used for economic potential to incorporate location-based value streams consistent with the geospatial load forecasts, includes additional demand side technologies beyond EE, and also integrates weather uncertainty. For the MPS, however, these features were not used, and cost-effectiveness was calculated similarly to prior work with the AceGuru tool that DSMore replaced.

In addition, the new toolkit allows the DER program portfolio to be developed based on additional metrics. Historically, NV Energy’s EE portfolio has been designed to maximize annual energy savings, subject to cost-effectiveness evaluation. The new DER evaluation framework is capable of designing portfolios with the same approach, or to maximize ratepayer cost savings, source energy savings, GHG emission reductions, or other metrics. As part of the “walk, jog, run” approach, the MPS begins to incorporate this with the development of a “Grid Value” Portfolio as described in the testimony of Tom Hines. The inclusion of new metrics makes it possible to consider and design the DER program portfolio for multiple objectives.

13. Q. HOW WAS THE DER EVALUATION FRAMEWORK USED TO PRODUCE THE MPS RESULTS?

A. A detailed 10-step process is described in the MPS Report, however, the following provides a high-level synopsis:

- Steps 1 through 4 defined the scenarios and produced the stock roll-over outputs that are used in Step 6 to produce technical potential.
- Step 5 prepared the data and inputs to use DSMore for cost-effectiveness evaluation of the portfolio. In addition to the MPS Report content, Mr. Kenneth Skinner’s testimony also describes this step.
- Step 6 through 10 developed the technical potential, economic potential, maximum achievable potential, and realistically achievable potential. In addition to the MPS itself, Mr. Tom Hines’ testimony also describes these steps.

14. Q. ARE THERE OTHER POTENTIAL USES FOR THIS DER EVALUATION FRAMEWORK?

A. Yes, there are many other potential uses for the DER evaluation framework. These applications are still in the testing and evaluation phase.

One potential application is to use the geospatial allocation of a scenario’s DER adoption to evaluate distribution system impacts in the DRP. This framework would also allow the DRP to evaluate “what if” scenarios that include, for example, higher EV adoption.

Another potential application is to create consistent scenarios of load forecast and DER portfolios for the Integrated Resource Planning (“IRP”) process, DRP and MPS. In addition to informing a wider range of possible load futures in the IRP and DRP, this would improve the estimates of avoided ratepayer costs, GHG emissions, and source energy savings associated with each scenario.

Another potential application is to design DER portfolios that emphasize different objectives such as ratepayer value, source energy emissions, or GHG emissions (or some combination thereof). An initial phase of this work is presented by the “Grid Value” portfolio in the MPS.

SECTION III: MODEL DESCRIPTIONS, AND REASONS FOR THEIR USE

15. Q. WHAT IS THE PATHWAYS TOOL AND WHAT IS ITS PURPOSE?

A. PATHWAYS is an economy-wide energy and infrastructure model that calculates energy consumption and GHG emissions for each sector of the economy, including transportation, buildings, electric generation, industry, agriculture and land use and other sectors. It uses a stock rollover model to calculate energy and GHG savings potential by sector and end use category. The stock rollover in the model is based on the total number of devices installed in a region for each sector and end use, the number of new devices to be installed due to growth, the number of “early replacement” devices (if any), and average effective useful life for each device. By tracking the replacement rate of equipment, PATHWAYS provides the number of opportunities for adoption of new efficient devices.

PATHWAYS is used to model a range of future scenarios that achieve economywide decarbonization or other policy goals. PATHWAYS can demonstrate the timing and impact of efficiency and electrification on the electric grid across different scenarios to inform utility planning. Additionally, the stock and sales outputs of the model can be used for detailed analysis of adoption and to inform the MPS.

16. Q. WHAT SECTORS AND TECHNOLOGIES ARE MODELED IN PATHWAYS FOR THE MPS?

A. The PATHWAYS model includes multiple sectors and subsectors for energy service demand relevant for the MPS. Specifically, there are 15 residential subsectors, nine commercial subsectors, and six transportation subsectors, or 30 total subsectors captured in the stock rollover section of the model for the MPS. Together, these sectors include 117 technologies. Additionally, the MPS used the PATHWAYS model framework to project future adoption of other additional DER types, including behind-the-meter (“BTM”) solar, BTM storage, DR in residential and commercial buildings, managed EV charging, and non-equipment and behavioral energy efficiency.

17. Q. WHAT INPUT DATA WERE USED IN PATHWAYS IN THIS STUDY?

A. To prepare a PATHWAYS model specific to NV Energy, E3 benchmarked to the State of Nevada using data from the U.S. Energy Information Administration’s (“EIA”) State Energy Data System (“SEDS”). Initial subsector and device level details were developed by combining government data on device stocks, device shares, device efficiency, and service demands from various sources, most importantly EIAs Annual Energy Outlook, SEDS, EIA’s Residential Energy Consumption Survey (“RECS”), EIA’s Commercial Building Energy Consumption Survey (“CBECS”), and National Renewable Energy Laboratory (“NREL”) Annual Technology Baseline (“ATB”). Default assumptions were updated with NV Energy specific data when available.

E3 then adapted the model of Nevada to describe the Nevada Power and Sierra service territories. These models were first scaled down from the Nevada model

using customer counts and population data for each territory. The model description of energy technology in the two territories was refined with data from NV Energy’s 2016 Residential Appliance Saturation Survey (“RASS”), its 2017 Market Potential Study, and its load forecast. Finally, model outputs were benchmarked against historic electricity consumption data.

The final set of assumptions in PATHWAYS are the sales shares of new and replaced equipment for each device type, which vary by scenario. To develop these assumptions the analysis team considered several policy, economic, and market factors that influence the adoption rate of DERs. Those factors include:

- fossil fuel prices;
- electricity rates;
- upfront equipment/device costs;
- federal, state, and utility incentives;
- customer preferences and attitudes;
- supply chain constraints;
- codes and standards; and
- other federal, state, and utility policy.

PATHWAYS does not model how a specific factor spurs adoption. Instead, the scenarios are designed to capture a wide range of possible policy and economic futures. There are many possible combinations of factors that could lead to the adoption rates modeled in PATHWAYS for each scenario.

18. Q. WHAT SCENARIOS WERE EVALUATED AND WHAT WERE THE RESULTS?

A. The MPS explored the six future scenarios of DER adoption, including EE, building electrification, transportation electrification, BTM solar, BTM storage, and DR described below. The scenarios were designed to explore a wide range of potential futures and reflect varying policy and market landscapes. There were many considerations that went into the development of key PATHWAYS inputs, including annual sales shares of DERs.

The Deep Decarbonization and High Scenarios were developed to achieve GHG reduction targets outlined by the State of Nevada in the 2019 Senate Bill 254 (“SB254”). The Deep Decarbonization scenario achieves interim goals of 28 percent reduction below 2005 levels by 2025, forty-five percent reduction by 2030, and net-zero by 2050. The High Scenario does not achieve the interim targets, but it achieves the mid-century net-zero goal.

The Reference Scenario is intended to reflect DER adoption assuming no change to existing federal, state, and utility policy and no dramatic shifts in market trends.

The Mid Scenario is intended to reflect a continuation of existing policies and market conditions in the near term but higher policy ambition and market transformation starting around 2030 which accelerates the deployment of DERs.

The Low Scenario reflects lower DER adoption due to unfavorable market forces or policy changes.

These scenarios explore varying levels of adoption of all DER types. The Deep Decarbonization and High Scenarios, which were designed around decarbonization targets, have high rates of building and transportation electrification which were coupled with aggressive EE and DR adoption.

The Technical Potential Scenario was developed to explore the maximum EE potential. This scenario assumes that customers choose the most efficient device option available on the market upon burnout of existing equipment and in new construction and there is no fuel switching in retrofit applications. The scenario also assumes that all customers participate in non-equipment EE programs such as home energy reports and smart thermostats. This scenario was developed to explore only the technical potential for EE and not the technical potential for other DERs evaluated in the MPS.

19. Q. WHAT IS THE FORECASTING ANYWHERE TOOL AND WHAT IS ITS PURPOSE?

A. Forecasting Anywhere is a model developed by E3 and IA that performs a granular geospatial allocation of regional DER adoption scenarios. It is a streamlined version of the more sophisticated LoadSEER software, which is being deployed at NV Energy. Regional DER adoption scenarios are developed to be consistent with federal and state policy goals and energy utility long-term resource plans, in this case, using PATHWAYS. Forecasting Anywhere uses a combination of machine-learning and heuristics analysis with a wide variety of datasets to estimate which customers are more or less likely to adopt a DER technology and perform a spatial and temporal allocation of that DER. Forecasting Anywhere provides DER adoption and load forecasting scenarios for distribution planning and integrated

grid planning that are consistent with the scenarios used for generation and transmission planning. It also allows for assessments of DER adoption and allocation within specific customer groups, communities or geographic regions.

Forecasting Anywhere was used to provide NV Energy with a geospatial DER adoption forecast at the census block group level to inform the development of their DRP and to support the analysis of DER adoption impacts in LMI communities for the MPS.

20. Q. WHAT IS DSMORE AND WHAT IS ITS PURPOSE?

A. DSMore is a cost-effectiveness evaluation tool developed by IA for designing and evaluating DSM program measures and portfolios. It is used by dozens of utilities to evaluate the impacts and cost-effectiveness of DSM and DER programs. The model inputs individual measures, program portfolios, avoided costs and program costs to calculate kW, kWh and GHG impacts and the industry standard cost-tests used to evaluate cost-effectiveness from a variety of perspectives. For the NV Energy MPS, DSMore was used to determine economic potential based on the cost-effectiveness test results. Additional details on DSMore are provided in the testimony of Mr. Kenneth Skinner.

SECTION IV: SCENARIOS CONSIDERED AND RELEVANT OUTPUTS

21. Q. PLEASE DESCRIBE THE SOURCE ENERGY AND EMISSIONS METRICS DEVELOPED BY E3.

A. NV Energy's current DSM portfolio is designed with the objective of delivering energy savings, subject to cost-effectiveness. With the new DER evaluation framework, other objectives can be evaluated. E3 explored several alternative

portfolio metrics that could align portfolios with broader goals of better targeting DSM measures that reduce system cost and/or reduce GHG emissions.

As an illustration of alternative objectives, E3 developed two interim metrics to guide portfolio design considerations that highlight specific hours of grid need. These were then used in developing the Grid Value portfolio. The two metrics are the hourly marginal source energy and hourly marginal emissions. These metrics were selected based on availability of data, along with being able to provide a signal for hours with high-emissions on the grid, hours with higher likelihood of capacity constraints, and generally high-cost hours on the grid.

These metrics can either be calculated for first year savings or lifecycle savings. First year savings align with current expected system conditions, while lifecycle savings reflect projected changes to NV Energy's bulk grid resource portfolio over time. Note that these metrics, as reported, do not include impacts of line losses; those are incorporated in other parts of the analysis in DSMore.

The first metric, *hourly marginal source energy*, is defined as the marginal change in fossil fuel energy input into the marginal electricity generator, per unit of site energy consumed, to meet a marginal change in site energy consumption. This metric is calculated based on forecasted hourly marginal electricity prices, along with underlying wholesale commodity gas costs. Forecasted hourly marginal energy prices were provided by NV Energy from a production simulation model run, consistent with NV Energy's fifth amendment to its 2021 IRP (Docket No. 23-08015). Forecasts were provided through 2052.

The second metric, *hourly marginal emissions*, is defined as the marginal change in GHG emitted per unit of site energy consumed, to meet a marginal change in site energy consumed. It is calculated based on the same hourly implied marginal heat rate, but heat rate is converted to CO₂-equivalent emissions, based on the carbon intensity of combusting natural gas.

22. Q. PLEASE DESCRIBE THE PATHWAYS FEASIBILITY SCREENING PROCESS.

A. The PATHWAYS feasibility screening process is designed to understand which scenarios to use in the DER evaluation framework, and other planning processes, by computing five metrics for each scenario that summarize the technical, societal, and economic challenges associated with each scenario, as follows:

1. **Total direct costs** - the total amount of spending on energy-consuming devices, fuels, and electricity in each scenario;
2. **Average household costs** - the average change in household energy costs due to spending on appliances, vehicles, fuel, and electricity costs;
3. **Capital investment** - the total amount of capital expenditures on energy-consuming devices alone. This captures the differences in upfront costs that consumers will face in each scenario;
4. **Customer behavioral changes** - the difference in pace of adoption for new and potentially disruptive technologies not yet widely adopted in Nevada, like heat pumps; and
5. **Achievement of GHG emissions reductions** - the extent to which each scenario achieves GHG emissions reductions that will support the state of Nevada's economy-wide GHG targets.

The feasibility screening results are presented in the MPS and highlight differences between each of the scenarios. Independently from the feasibility screening results, the Mid Scenario was selected to develop the realistically achievable potential in the MPS.

23. Q. WHY WAS THE MID SCENARIO USED IN THE MPS?

A. The Mid Scenario was used in this MPS for several reasons that together make it a reasonable choice for an initial use of the new DER evaluation framework. First, it reflects existing policy through 2030, so it does not include either a slow-down or acceleration of policy factors that would affect adoption. Second, the Mid Scenario is most aligned with historical NV Energy DSM program practices, which makes it a good candidate for the “walk, jog, run” approach because it results in familiar scenarios. Third, the Mid Scenario can be reasonably benchmarked to prior market potential study results since it has similar underlying assumptions. Finally, the Mid Scenario scored well on the Feasibility Screen relative to other scenarios indicating that it is a plausible scenario.

The Mid Scenario was also the most consistent with NV Energy’s forecast of ratepayer avoided costs being used for measure and portfolio cost-effectiveness evaluation. In future iterations of the DER evaluation framework, ratepayer avoided costs would be consistent with whichever scenario or scenarios are selected.

24. Q. WHAT ARE THE KEY RESULTS FROM THE PATHWAYS ANALYSIS?

A. Detailed results from the PATHWAYS analysis are provided in the MPS Report. The analyses provide an assessment of adoption, energy impacts, and peak impacts

of EE, building electrification, transportation electrification, DR from end uses in buildings, DR from managed EV charging, and BTM solar and storage for each scenario. Additionally, the PATHWAYS analysis provides total annual load forecasts through 2054 under each scenario.

Although each PATHWAYS scenario presents distinctly different views on the pace and scale of electrification and decarbonization, load growth differs modestly across scenarios for three key reasons:

1. Data centers and new major projects, which have little EE potential, are large contributors to load growth in the Nevada Power and Sierra territories through the modeling horizon.
2. The outlook for transportation electrification is similar across scenarios, particularly for light-duty vehicles due to strong market conditions and supportive federal policy.
3. Scenarios with high rates of building electrification also have ambitious levels of EE, offsetting load growth.

The key findings for each DER type modeled are summarized below:

- **EE:** Air conditioning, commercial space heating, commercial lighting, and non-equipment measures are some of the largest sources of EE modeled in the PATHWAYS scenarios. The scenarios demonstrate a wide range of EE reflecting varying levels of ambition as well as the opportunities for efficiency unlocked by building electrification.
- **Building Electrification:** The scenarios differ significantly in the amount and pace of building electrification. In scenarios that electrify a majority or most space and water heating in residential and commercial buildings,

investing in high efficiency heat pumps rather than standard performance heat pumps can significantly reduce the amount of load growth expected.

- **Transportation Electrification:** As noted above, the outlook for transportation electrification is high across all scenarios. Most of the load growth from transportation electrification is driven by light-duty vehicles, and the outlook for medium- and heavy-duty vehicle electrification varies more significantly across scenarios than light-duty vehicle electrification.
- **BTM Solar and Storage:** While the scenarios differ in the near- to mid-term on the degree of BTM solar adoption, the long-term trajectory of installed solar capacity is similar across scenarios reflecting some degree in market saturation. The outlook for BTM storage varies more significantly across scenarios reflecting uncertainty in how policy and market forces could influence adoption.
- **DR:** The analysis focused on DR from Heating, Ventilation and Air Conditioning and managed charging as two of the larger sources of DR potential. Managed charging was shown to significantly mitigate the peak load impacts of transportation electrification. The analysis considered several trajectories expanding upon NV Energy's existing DR programs targeting air conditioning loads, which vary in the degree to which NV Energy can successfully expand enrollment and retain participants.

25. Q. WHAT RESULTS WERE SPECIFICALLY USED TO DEFINE TECHNICAL POTENTIAL? PLEASE SHARE A SUMMARY OF THE OUTPUTS.

A. The key results from the PATHWAYS analysis supporting the development of DSM technical, economic, maximum achievable, and realistically achievable

potential are the stock rollover and new customer growth outputs of the model. These reflect the number of “opportunities” for EE upgrades when customers are replacing equipment at the end of its useful life. No early retirements of technologies were assumed before their end of life. In his testimony, Mr. Tom Hines describes how this stock rollover data was used in the development of technical potential.

26. Q. WHY ARE STOCK REPLACEMENT RESULTS FROM PATHWAYS APPROPRIATE FOR THE MPS?

A. Stock replacements from PATHWAYS provide an estimate of the annual sales of devices, which are the number of consumer decision-points to adopt a new technology. This is consistent with existing conventions for technical potential based on a replace-on-burnout program design.

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

A. Yes.

EXHIBIT PRICE-DIRECT-1



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ENERGY AND ENVIRONMENTAL ECONOMICS, INC.

San Francisco, CA

Senior Partner

Mr. Price joined E3 in 1993 and Distributed Energy Resource (DER) practice area. For over 25 years, he has helped state and federal government agencies, utilities, and technology companies recognize and support a clean energy transition. His work in regulatory analysis focuses on evaluation of DER cost-effectiveness and he has contributed to assessments of the largest and most sophisticated DER programs in the U.S., including those in California, New York, and other states. He has also built several tools to support utility planning and assessment of distributed resources as well as rooftop solar, energy storage, advanced demand response, building standards, and other resources. In 2012, Mr. Price co-authored a landmark E3 article in the journal *Science* exploring the pivotal role of electrification in achieving deep greenhouse gas reductions. His clients include state agencies such as California Public Utilities Commission, California Energy Commission, New York State Energy Research and Development Authority; utilities such as Pacific Gas and Electric, Consolidated Edison, Southern California Edison, National Grid; and technology companies and others. Some select projects at E3 by practice area include:

Distributed Energy Resources:

- Technical lead for New York City Local Law 97 Implementation Action Plan for the NYC Department of Energy Management. This project, currently underway, charts an implementation plan to achieve 40% reductions in greenhouse gas emissions in city operations by 2025, and 50% reduction by 2030.
- Lead investigator for the development of California's Avoided Costs (2004 to Present). Mr. Price oversees the E3 work on the cost-effectiveness framework for California's DER cost-effectiveness assessment used to evaluate the nearly \$2 billion per year portfolio.
- Lead investigator for the development of the Time-Dependent Valuation (TDV) methodology adopted by the California Energy Commission for the 2005, 2008, 2013, 2016, and 2019 Title 24 Building Standards.
- Led numerous analyses on the cost-effectiveness of Net Energy Metering for state commissions, energy offices, and legislatures. Work was completed in California, Nevada, New York, and other states and jurisdictions.

Energy Transition:

- Led analysis of the impact of California's Assembly Bill 32 (Global Warming Solutions Act) on the electricity sector for the California Public Utility Commission (CPUC) and California Air Resources Board (CARB). Continues to lead the E3 team in supporting the ARB in periodic Scoping Plan Updates.
- Principal Investigator for New York State Energy Research and Development Authority in the development of deep decarbonization scenarios for New York in support of the CLCPA.

- Updated the energy efficiency framework to allow California’s public purpose funds to be spent on fuel switching subject to emissions, source energy, and cost-effectiveness criteria.

Energy Efficiency and Demand Response:

- Supported the work to develop the U.S. EPA / DOE *National Action Plan for Energy Efficiency*. Led the development of materials for the Leadership Group on the following topics: the business case for energy efficiency; decoupling and incentives for utility shareholders; and integrating energy efficiency in resource planning. Provided material contributions to the 2015 DOE *Quadrennial Energy Review* on energy efficiency, solar rooftops, and energy storage.
- Led the team that developed the CPUC Demand Response cost-effectiveness tool, the “DR Screening Template.” Supported the California ISO in its response to FERC regarding Order 719 and the status of demand response in California. Supported the Lawrence Berkeley National Lab Demand Response Potential Study released in 2016.

Integrated Distribution Planning:

- Since 1993, Mr. Price has led dozens of studies and pilots on the economics of distributed resources across a range of technologies including renewables, energy storage, combined heat and power, demand response, and energy efficiency. He has evaluated numerous local integrated resource planning (LIRP) analyses for distribution utilities and developed several economic and reliability screening tools to evaluate distributed resource.

Education

Stanford University
M.S., *Engineering Economic Systems and Operations Research*

Palo Alto, CA
1998

Awarded a Research Assistantship to study the proposed structure of California’s electric utility industry after deregulation

Swarthmore College
B.A., *Economics and B.S., Engineering*

Swarthmore, PA
1993

Citizenship

United States

Selected Professional Reports and Publications

1. **A. Mahone, Dr. Z. Subin, J. Kahn-Lang, D. Allen, V. Li, G. De Moor, Dr. N. Ryan, S. Price “Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model” (2018).**
2. **Aas, D., S. Bharadwaj, A. Mahone, Z. Subin, T. Clark, S. Price “Pacific Northwest Pathways to 2050” (2018).**

3. Price, S., Z. Ming, A. Ong "Nevada Net Energy Metering Impacts Evaluation 2016 Update" (2016)
4. **J. Williams, A. DeBenedictis, R. Ghanadan, A. Mahone, J. Moore, W. Morrow III, S. Price, M. Torn, "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity" *Science* 06 Jan 2012: Vol. 335, Issue 6064, pp. 53-59.**
5. Sreedharan, P., D. Miller, S. Price and C.K. Woo (2012) "Avoided cost estimation and cost-effectiveness of permanent load shifting in California," *Applied Energy*, 96, 115-121.
6. Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," *Energy*, 35, 1609-1614.
7. DeBenedictis, A., T. E. Hoff, S. Price and C.K. Woo (2010) "Statistically Adjusted Engineering (SAE) Modeling of Metered Roof-Top Photovoltaic (PV) Output: California Evidence," *Energy*, 35, 4178-4183.
8. *California Greenhouse Gas Modeling of the Electricity Sector, Commissioned by the California Public Utilities Commission, and the California Air Resources Board.*
9. **An Update to California Time-Dependent Valuation in Title 24. Analysis, Methodology, and Stakeholder Process in the 2005, 2008, 2013, 2016, and 2019 Title 24 Code Cycles.**
10. Woo, C.K., E. Kollman, R. Orans, S. Price and B. Horii (2008) "Now that California Has AMI, What Can the State Do with It?" *Energy Policy*, 36, 1366-74.
11. Orans, R., S. Price, J. Williams, C.K. Woo and J. Moore (2007) "A Northern California - British Columbia Partnership for Renewable Energy" *Energy Policy*, 35:8, 3979-3983 (Lead article).
12. *National Action Plan for Energy Efficiency, U.S. Environmental Protection Agency, Washington D.C., 2006, Authors not cited – S. Price was a contributing author.*
13. **Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, California Public Utilities Commission, San Francisco, CA (2004). Authors: R. Orans, C.K. Woo, B. Horii, S. Price, A. Olson, C. Baskette, Joel Swisher.**
14. *Phase 1 Results: Establish the Value of Demand Response, Orans, Ren et al. Energy and Environmental Economics. DRRC Report. LBNL-60128 Collaborative Report. April 2006.*
15. *Assessment of California CHP market and Policy Options for Incremental Penetration, EPRI, Palo Alto, CA California Energy Commission, Sacramento, CA 2005. Senior Principal Investigators: K. Darrow, S. McNulty, S. Price.*
16. Hartway, R., S. Price and C.K. Woo (1999) "Smart Meters, Customer Choice and Profitable Time of Use Rate Option," *Energy*, 24, 895-903.

AFFIRMATION

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

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



Date: 5/31/2024

Snuller Price

TOM HINES

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 ____

Prepared Direct Testimony of

Tom Hines

SECTION I: INTRODUCTION

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

A. My name is Tom Hines. I am a Principal and Co-founder of Tierra Resource Consultants LLC (“Tierra”), a consulting firm that provides energy and carbon management consulting services to NV Energy. Tierra provided market potential analysis and program design support for NV Energy’s Demand Side Management (“DSM”) portfolio of programs as part of this filing. My business address is 1501 North Broadway in Walnut Creek, California. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, “NV Energy”).

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

A. My professional experience includes more than 30 years of DSM program design, evaluation, market research, and analysis. I have extensive DSM planning, Integrated Resource Planning (“IRP”) and regulatory policy experience, including serving as a DSM expert witness in regulatory proceedings across three states –

1 Arizona, North Carolina, and Florida. My DSM program design efforts have
2 earned more than twenty industry awards from industry organizations including
3 American Council for an Energy-Efficient Economy (“ACEEE”), Association of
4 Energy Services Professionals (“AESP”), Energy Systems Integration Group
5 (“ESIG”), Peak Load Management Alliance (“PLMA”), Smart Electric Power
6 Alliance (“SEPA”), and the US Department of Energy/Environmental Protection
7 Agency (“DOE/EPA”). Much of my work experience has been in the desert
8 southwest region in Arizona where I am well versed in regional energy use trends,
9 changing resource needs and avoided cost values, and the process of re-evaluating
10 and optimizing DSM portfolios to maximize the value of programs delivered.

11
12 My statement of qualifications is attached as **Exhibit Hines-Direct-1**.

13
14 **3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**
15 **CURRENT POSITION?**

16 A. In my current position as Principal, my duties encompass a broad range of
17 responsibilities pertaining to the delivery of DSM program portfolio design,
18 development, and optimization services to help electric utilities in North America
19 better align customer loads and energy usage with changing utility resource needs.
20 This includes conducting market potential and grid value analyses, as well as
21 optimizing DSM program portfolios for a range of utilities including Arizona
22 Public Service (“APS”), Duke Energy, Seminole Electric, and Tucson Electric
23 Power (“TEP”). Other services I provide include forecasting of Demand Response
24 (“DR”) and Energy Efficiency (“EE”) impacts for integration into load forecasts
25 and resource planning models, and development and evaluation of distributed
26 resources in all-source Request for Proposals (“RFPs”) to procure utility resources

including contracting for multiple Distributed Energy Resources (“DER”) grid services. I also deliver impact and process evaluations based on in-depth customer experience research with program participants and non-participants, as well as perspectives from trade allies. Furthermore, I provide strategic implementation support for utilities to develop new DSM technology programs and pilot initiatives including administration of a U.S. Department of Energy Connected Communities grant project in partnership with Duke Energy in North Carolina to equip approximately 1,000 homes with connected devices including smart thermostats, water heater controls, energy storage systems, and home energy monitors to deliver valuable energy savings and peak load reductions while exploring new business models.

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

A. No.

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

A. Together with the testimony of witness Snuller Price at E3, I sponsor the NV Energy DSM Market Potential Study (“MPS”) Report contained in Technical Appendices DSM-25. In addition, I supported NV Energy with the development of the Traditional and proposed Grid Value DSM portfolios for 2025-2027. The purpose of my testimony is to explain how the outputs from the PATHWAYS model were used to develop a forecast of realistically achievable EE and DR savings potential over the MPS period (2025-2040) and how the potential study

results were used to develop the 2025-2027 Traditional and Grid Value DSM portfolios for NV Energy.

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

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

Exhibit Hines-Direct-1 – Statement of Qualifications.

I am sponsoring the following Technical Appendix: DSM-25.

7. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section II, I explain how technical potential, economic potential, maximum achievable potential, and realistic achievable potential was developed as part of the Market Potential Study. In Section III, I explain how the results of the MPS were used to develop the Traditional and Grid Value DSM portfolio plans.

SECTION II: MARKET POTENTIAL STUDY RESULTS

8. Q. PLEASE BRIEFLY DESCRIBE THE PATHWAYS MODEL.

A. PATHWAYS is a stock rollover model developed by E3 that served as the starting point for calculating technical, economic, max achievable, and realistically achievable potential. For more information about the PATHWAYS model, please refer to Snuller Price's testimony.

9. Q. PLEASE EXPLAIN HOW THE RESULTS FROM THE PATHWAYS MODEL WERE USED IN DEVELOPING THE FORECASTED EE AND DR SAVINGS POTENTIAL IN THE MARKET POTENTIAL STUDY?

A. To determine the forecasted potential, Tierra conducted a four-step process that includes calculating technical potential, economic potential, maximum achievable

potential, and realistic achievable potential. To calculate technical potential in the first step, annual equipment stock turnover and sales data from PATHWAYS for the “Mid” DER adoption scenario were allocated to and multiplied by verified energy and demand savings for each measure considered in the study. The “Mid Scenario” is intended to reflect a continuation of existing policies and market conditions in the near term but higher policy ambition and market transformation starting around 2030, which accelerates the deployment of DERs.

10. Q. PLEASE EXPLAIN WHY THIS APPROACH WAS USED AND HOW IT COMPARES TO PRIOR NV ENERGY MARKET POTENTIAL STUDIES.

A. This approach follows the approach taken in prior studies. Specifically, the use of stock turnover and annual sales data as the basis for calculating technical potential was used in the previous Market Potential Study conducted in 2018. Maintaining this basic approach across studies allows for consistent comparison with prior potential results while also providing additional value for planning and scenario development through PATHWAYS to offer both NV Energy territory-specific market and total Nevada statewide market characterization.

The approach to estimate DSM potential is directly linked with the larger overall PATHWAYS market analysis to enable a more robust understanding of the market opportunities that exist for DSM programs, including the potential effects of various policy scenarios and the resulting differences in the relative pace of DER adoption. As such, this approach also supports strategic planning of potential future policy scenarios that could impact and potentially accelerate transportation and building electrification adoption that could help drive greater DSM potential. Furthermore, integration with the Forecasting Anywhere tool provides geospatial

information for system planning purposes to provide a more integrated view of DER adoption and potential DSM program locational impacts and benefits.

11. Q. WHAT METHODOLOGY WAS USED TO CALCULATE ECONOMIC AND ACHIEVABLE EE AND DR SAVINGS POTENTIAL AND HOW DOES IT COMPARE TO PRIOR MARKET POTENTIAL STUDIES?

A. The methodology used to calculate economic and achievable EE and DR savings potential includes multiple steps. Each are consistent with prior practices and described below.

Building from the first step of calculating technical potential, as discussed in the response to Q&A 9 above, the second step in the Market Potential Study process is calculating economic potential. Economic potential was determined by removing technical potential for measures that have a benefit cost ratio less than 1.0 based on Nevada's Non-Energy Benefits Total Resource Cost Test ("NTRC"). This was the same methodology used in the previous MPS, but this study employs a different model that uses DSMore as the basis for calculating the NTRC benefit cost ratios. Please refer to the testimony of Kenneth Skinner from Integral Analytics for more detail on DSMore.

The third step in the process is the calculation of maximum achievable potential which consists of two adjustments to economic potential. First, it was assumed that 15 percent of the population will not be responsive to any program marketing, and therefore will not participate in a program and contribute to achievable potential. This is consistent with assumptions made in the previous MPS. Second, after adjusting for the 15 percent of the population that will not be responsive to program

marketing, maximum achievable potential was calculated as the fraction of the remaining economic potential that can be achieved based on offering incentives or rebates that cover 90 percent of the incremental cost to customers. This fraction is determined using market payback acceptance curves and participant-focused economics that quantify the relationship between adoption of EE technologies and the length of time needed to recoup the customers investment in the EE technology. Market payback acceptance curves were used for an EE potential study for another electric utility in the US desert Southwest.

The fourth and final step in the process is the calculation of realistically achievable potential. This was calculated as an adjustment to maximum achievable potential to account for additional constraints and qualitative market limitations based on NV Energy's local program implementation experience and Tierra's experience implementing programs in other states.

12. Q. WHAT ARE THE FORECASTED RESULTS FOR ECONOMIC, MAXIMUM AND REALISTIC ACHIEVABLE POTENTIAL?

A. As described in the MPS, in total, approximately 68 percent of measures and 47 percent of technical potential for energy savings (75 percent of technical potential for demand savings) did not pass the NTRC screen and were not included in economic potential across both Nevada Power and Sierra. This results in an estimated 353.8 GWhs (Nevada Power) and 145.4 GWhs (Sierra) of economic EE savings potential in 2025, rising to an estimated 961.8 GWhs (Nevada Power) and 390.5 GWhs (Sierra) in 2040.

Out of the potential savings that is included in the economic potential for energy savings, 72 percent is considered to be part of the maximum achievable potential

given the practical constraints to consumer marketing and customer adoption curves and 63 percent is considered to be realistically achievable potential given historical and typical customer rebate amounts. For demand savings, 37 percent of the economic potential is determined to be the maximum achievable potential, while 35 percent is realistically achievable.

The maximum achievable potential forecast resulted in an estimated 251.1 GWhs (Nevada Power) and 108.9 GWhs (Sierra) of maximum achievable EE savings potential in 2025, rising to an estimated 662.1 GWhs (Nevada Power) and 290.0 GWhs (Sierra) in 2040. The realistically achievable forecast resulted in an estimated 231.3 GWhs and 115.8 MWs of maximum achievable EE savings and peak demand savings potential in 2025 for Nevada Power, rising to an estimated 600.1 GWhs and 390.9 MWs in 2040. For Sierra, the forecast resulted in an estimated 84.4 GWhs and 20.3 MWs of maximum achievable EE savings and peak demand savings potential in 2025, rising to an estimated 242.9 GWhs and 81.0 MWs in 2040.

SECTION III: TRADITIONAL AND GRID VALUE DSM PORTFOLIO PLAN

DEVELOPMENT

13. Q. HOW DOES THE FORECAST FOR REALISTICALLY ACHIEVABLE POTENTIAL COMPARE TO THE CURRENT ANNUAL EE SAVINGS GOAL OF 1.1 PERCENT OF RETAIL SALES?

A. The analysis of maximum achievable and realistic achievable potentials in both the Traditional and Grid Value portfolios revealed challenges in achieving the historic goal of annual energy savings equivalent to 1.1 percent of annual retail sales. This is due to several factors including the success of codes and standards in reducing

the region's remaining cost-effective energy efficiency opportunities as well as significant load growth in sectors that have fewer opportunities for incremental energy efficiency savings through utility programs, including data centers and transportation electrification. The challenge of cost-effectively achieving the historic goal in the future reflects the success of promoting energy efficiency throughout the state of Nevada and provides an opportunity for NV Energy to transition its DSM portfolio to one that emphasizes the value of flexible distributed capacity and responds to broader market changes towards renewable integration, decarbonization, and electrification.

14. Q. PLEASE DESCRIBE HOW THE MARKET POTENTIAL STUDY RESULTS WERE USED IN DETERMINING THE PROPOSED PORTFOLIO AND SCOPE OF PROGRAMS.

A. Tierra, with input from E3, mapped PATHWAYS outputs to DSMore measure inputs to align the technology-level calculations in PATHWAYS with the measure and program-level DSMore cost-effectiveness calculations used for the MPS and to facilitate the portfolio design process. This approach directly links the potential study and portfolio design workstreams by translating PATHWAYS outputs into specific DSM measures that are either already offered through NV Energy's existing DSM programs or could be potentially incorporated into NV Energy's portfolio in the future. Note that some technologies, such as efficient transportation technologies, are not included in the potential study or portfolio design because they are not currently considered elements of DSM programs.

15. Q. PLEASE DESCRIBE WHY SEVERAL MEASURES THAT ARE
ESTIMATED AS HAVING ZERO POTENTIAL IN THE MARKET
POTENTIAL STUDY ARE INCLUDED AS OFFERINGS IN THE
PROPOSED PORTFOLIO.

A. To create comprehensive program offerings that address key customer segments and energy end uses, the Grid Value and Traditional portfolios developed by Tierra and proposed by NV Energy include measures that were found to have zero realistic achievable potential. This is due to differences in how cost-effectiveness informs decision making between the Market Potential Study and the portfolio design process. The MPS conducts the NTRC screen at the measure level, while the portfolio design broadens the requirement of an NTRC of greater than or equal to 1.0 to the portfolio level. This allows NV Energy to include measures in the portfolio that have an NTRC ratio of less than 1.0 (and were therefore not included in the realistically achievable potential), as long as the overall portfolio provides positive net benefits for NV Energy customers. Doing so, allows NV Energy to provide more robust and comprehensive DSM programs for all customer segments, including historically underserved communities such as multi-family and limited-income customers and other hard to reach customers such as schools and small businesses while also ensuring that the overall DSM portfolio is cost effective.

16. Q. PLEASE DESCRIBE THE OBJECTIVES FOR DEVELOPING BOTH A
TRADITIONAL AND GRID VALUE PORTFOLIO, AND THE APPROACH
THAT WAS USED TO DETERMINE THE TECHNOLOGIES INCLUDED
AND RELATIVE SCALE OF PROGRAMS IN EACH.

1 A. The objectives for developing the Grid Value portfolio focused on targeting savings
2 to the highest value times and maximizing flexible distributed kW capacity, while
3 the Traditional portfolio objectives focused on maximizing kWh savings at all
4 times. These metrics were then used to determine the alignment between savings
5 load profiles for different DSM technologies and hours of higher grid stress or cost,
6 to support achievement of different portfolio design strategies.

7
8 E3 and Tierra developed two additional interim metrics to guide portfolio design
9 consideration: 1) hourly marginal source energy and 2) hourly marginal emissions.
10 Please refer to Snuller Price's testimony for more information on these metrics.

11
12 As a result of this process, the Traditional DSM portfolio scenario primarily focuses
13 on existing programs and implementation strategies to achieve historic annual
14 energy savings (kWh) targets with relatively little emphasis on DR. It is designed
15 to build upon the existing 2024 DSM portfolio of programs to meet NV Energy
16 customers' growing demand for electricity, while maintaining system reliability,
17 addressing equity for historically underserved communities, and supporting energy
18 affordability for all customers.

19
20 The proposed Grid Value DSM scenario begins to transition the Traditional DSM
21 portfolio to a broader distributed flexible peak capacity focus. It provides greater
22 total net benefits for customers by combining the enhancements proposed for the
23 Traditional DSM portfolio with targeted investments focused on deploying diverse
24 demand side tools in addition to EE including demand response, load shifting, and
25 energy storage as well as coordinated managed electric vehicle charging to help
26 address the need to manage the impact of EV load growth on the grid, as described
27

in the Companies' Transportation Electrification Plan. Moreover, the Grid Value scenario also deploys a broader load management effort with customer education regarding the energy- and cost-saving benefits available by combining time of use ("TOU") rates with grid-enabled DERs and participation in NV Energy's load shifting and DR programs.

17. Q. PLEASE PROVIDE AN OVERVIEW OF THE KEY DIFFERENCES IN PROGRAM OFFERINGS FOR THE TRADITIONAL AND PROPOSED GRID VALUE PORTFOLIOS.

A. Both the Grid Value and Traditional portfolios deliver significant savings and benefits for NV Energy customers. While impact results between the Grid Value and Traditional scenarios will take some time to scale as new programs and technology are introduced, the Grid Value scenario already shows greater peak demand savings, lower total costs, and a higher net benefits for customers. In addition to maintaining high-value peak focused EE and addressing historically underserved customers, the Grid Value portfolio adds greater focus and investment in scaling dispatchable flexible capacity with connected DERS, including smart thermostats, batteries, water heater controls, pool pumps and greater options for C&I customers to participate in DR programs.

At this time, Tierra does not see significant differences between portfolios in the total source energy and emissions metrics. Over time, expectations are that increased impacts will be seen in these metrics from the Grid Value portfolio as participation grows, as modeling capabilities continue to evolve with the use of more granular DSM savings load shapes and new planning tool capabilities, and as

additional grid services can be developed and modeled. For more information on the proposed DSM portfolio programs, please see Adam Grant's testimony.

18. Q. BASED ON RESULTS OF THE MARKET POTENTIAL STUDY AND PROGRAM DESIGN, WHICH PORTFOLIO DOES TIERRA RECOMMEND?

A. Based on the analysis conducted, Tierra recommends the Grid Value portfolio. This is because it is forecasted to produce greater peak demand capacity savings and deliver higher net benefits for customers at a lower total cost than the Traditional portfolio. As proposed, the Grid Value portfolio will continue to offer a comprehensive suite of EE programs for all customer segments and provide targeted support for limited income customers and disadvantaged communities, while also driving greater net benefits by expanding the portfolio's focus on load management and dispatchable flexible DSM capacity resources. As loads continue to grow and future controllable technologies such as smart thermostats, managed EV charging, and battery storage come online, the incremental benefit of a Grid Value approach over a Traditional approach are forecasted to continue to increase over time across each of these metrics. In addition, as NV Energy continues to work with DSMore and the new suite of planning tools while working with stakeholders to better define new portfolio metrics, there will be opportunity to better model and capture additional potential grid value. This includes work to better define individual measure-level C&I DSM program load shapes as well as modeling combined effects of connected device control technologies that can be paired with time differentiated rates to create daily load shifting benefits for participants and the grid. And as these connected device demand response programs continue to evolve, NVE's valuation tools can incorporate the incremental value of

1 additional grid services such as voltage and frequency response which will drive
2 even higher incremental portfolio benefits for a Grid Value portfolio.
3

4 **19. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

5 A. Yes.
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EXHIBIT HINES-DIRECT-1

TOM HINES, MEP - PRINCIPAL

BIOGRAPHY

Tom Hines is a residential energy efficiency expert with more than 20 years of experience in program design, implementation, and evaluation. From 1997 through 2014, Mr. Hines has worked with Arizona Public Service Company (APS) in designing, developing, and managing the company's portfolio of residential energy efficiency programs, including: new homes, existing homes HVAC, home performance, consumer products lighting, pools, multi-family, behavioral conservation, and energy efficiency financing programs. Mr. Hines has designed, developed, and managed multiple award-winning energy efficiency programs, including the APS ENERGY STAR Homes program and the APS Home Performance with ENERGY STAR program. Throughout this time, Mr. Hines has worked closely with industry stakeholders to drive market transformation including builders, contractors, Realtors, lenders, raters, and other trade allies. In the new homes industry, Mr. Hines has been a key proponent of using applied building science principles and home performance testing tools to improve building efficiency and performance.

Mr. Hines has extensive experience working directly with the Arizona Corporation Commission (ACC) providing direct testimony, developing filings, and working directly with ACC staff during energy efficiency proceedings. Recent work includes acting as a strategic advisor on the design and development of APS' entire portfolio of DSM programs – working with program managers, implementation contractors, and evaluators to explore opportunities for maximizing cost effectiveness, and otherwise optimizing the APS portfolio of DSM programs. In this role, Mr. Hines prepares information and analysis on DSM program trends, technologies, opportunities, and challenges for senior executives and the utility's board of directors. From 1992-1997, Mr. Hines was a key technical resource developer for EcoGroup, a national energy efficiency services and consulting firm. In this role, Mr. Hines worked with over 30 utilities nationwide to develop home energy and water auditing tools that were delivered through an award-winning high school energy efficiency curriculum. Responsibilities included project management, creating recommendation logic tables, and calculating energy savings and environmental benefits. Mr. Hines holds a master's degree in environmental planning from Arizona State University and is a board member of "EEBA" the Energy and Environmental Building Alliance, an organization devoted to advancing building science and energy efficient building practices.

PROFESSIONAL EXPERIENCE

Integrated Distributed Energy Resource Planning and Design. Mr. Hines is currently a leading proponent of Distributed Energy Resource program design to address load shape challenges from high solar DG adoption on the grid, often referred to as the "duck curve." In this role at APS, Tom is tasked with coordinating with a wide range of utility disciplines, including resource planning, technology assessment, system operations planning, regulatory, smart grid, customer service, and rates to identify new and innovate approaches to distributed energy resource programs that support the continued

growth of solar, while minimizing grid impacts. Since 2013, Mr. Hines has been expanding this effort to other utilities including Tucson Electric Power, Sonoma Clean Power, and Cooperative Energy.

Energy Efficiency Portfolio Design for Commercial and Residential Programs. Mr. Hines oversees the annual energy efficiency portfolio design for Arizona Public Service. In this role, he has designed multiple

award-winning EE programs including new homes, home performance, HVAC, duct repair, quality install, pool pumps, and lighting. He works closely with program managers to review cost-effectiveness, calculate emission reductions, develop program budgets, design program modifications, and manage annual compliance targets. Recently, Tom has completed similar tasks for multiple electric Co-ops.

Policy and Strategic Consulting Support. Mr. Hines has provided EE regulatory support and policy development, including testimony at commission proceedings, meeting with commissioners and staff, developing filings and reports for APS. Tom was an integral player in the development of the Arizona EE Standards. He has extensive experience working with EE program cost effectiveness tests, stakeholder coordination, regulatory development, program implementation plans, EE savings forecasts, and integrating new technology options into existing compliance approaches. This expertise has extended to assisting in consulting with other utilities and the EPA ENERGY STAR program.

Distributed Storage Technology Evaluations and Pilot Design. Mr. Hines has assisted in multiple technology evaluations and pilot program designs for emerging battery, thermal storage, load management and demand response projects including APS' Solar Innovation Study, the APS Demand Response, Energy Storage and Load Management program, and Tucson Electric Power's Sustainable Communities Project. These efforts have included an evaluation of the technology, control systems, and build-out of the full program design.

Program Management and Implementation. Tom has directly managed a wide range of successful EE programs including residential lighting, HVAC, duct repair, pool pumps, and new homes. Tom has managed multi-million-dollar program budgets and consistently exceeded savings goals. As an industry leader in these roles, he has collaborated with or worked for over 30 electric, gas and water utilities nationwide sharing best practices and strategies for successful market transformation.

PROFESSIONAL HISTORY

Principal, Tierra Resource Consults, May 2017 – Present

President, Hines Consulting

Analyst/Project Manager, EcoGroup (Aclara)

EDUCATION

M.S., Environment Planning, Arizona State University, 1993

B.S., Psychology, Rutgers University, 1990

Professional Associations

Board of Directors, Energy and Environmental Building Alliance

CONTACT INFORMATION

1501 North Broadway Suite 300

Walnut Creek, CA 94596

Tom.Hines@Tierrarc.com

AFFIRMATION

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

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



Tom Hines

Date: 5/23/2024

DR. KENNETH SKINNER

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05_____

Prepared Direct Testimony of

Dr. Kenneth Skinner

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

A. My name is Dr. R. Kenneth Skinner. I am Vice President of Integral Analytics, Inc., (“IA”). My business address is One Riverfront Place, 300 Dave Cowens Dr #1010, Newport, KY 41071. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, “NV Energy” or the Companies”).

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

A. I earned a Ph.D. in Energy Economics from the Colorado School of Mines. I have over thirty years of energy industry experience including conservation, energy efficiency, demand response and integrated demand side management program design, potential assessment, measurement and verification, risk assessment, and cost-effectiveness analysis. Prior to beginning work with IA in 2006, I worked as an energy consultant leading the economic analysis and modeling of energy demand side energy projects including energy price forecasting, measurement and verification of energy savings, econometric analysis, optimization, and project risk

assessment. I have published hundreds of energy related papers and served as the technology columnist for Wiley Natural Gas and Electricity Journal. I am a noted speaker on energy related topics for organizations such as the Association of Energy Service Professionals, International Association for Energy Economics, American Council for an Energy-Efficient Economy, Peak Load Management Alliance, International Energy Program Evaluation Conference, Institute for Operations Research and the Management Sciences, and others. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Skinner-Direct-1**.

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

A. I am a co-developer of the award-winning efficiency cost-effectiveness software DSMore, and the location specific building assessment software Site-Optimizer, used in over 30 states by program administrators in program design and evaluation. I am the lead cost-effectiveness evaluator for utility energy efficiency and demand response programs from 2010 to 2024. Clients include NV Energy, Consumers Energy, DTE Energy (formerly Detroit Edison), AES Indiana (formerly Indianapolis Power and Light), Entergy, Louisiana Gas & Electric and Kentucky Utilities, and others. Comprehensive program design includes residential, commercial and industrial segments. I have led IA's Evaluation and Verification Services practice for utility energy efficiency and demand response programs from 2006 to 2024, which includes development of M&V plans and evaluation activities for utility clients according to the International Performance Measurement and Verification Protocol's ("IPMVP").

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

4 A. No.
5

6 5. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY
7 IN THIS CASE?

8 A. My testimony is in support of Section 3 Overview of the Financial Models in the
9 Demand Side Management (“DSM”) plan narrative and the proposal to migrate
10 from the Ace Guru cost-effectiveness model to the DSMore cost-effectiveness
11 model in the future. I describe the DSMore model and its use for the development
12 of the DSM plan and Distributed Resource Plan (“DRP”) and for the 2025-2027
13 Market Potential Study (“MPS”).
14

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

16 A. I am sponsoring **Exhibit Skinner-Direct-1**.

17 I am co-sponsoring or sponsoring the following Technical Appendices:

18 Technical Appendix DSM-27: 2025-2027 Market Potential Study

19 Technical Appendix DSM-28: DSMore User Manual

20 Technical Appendix DSM-29: DSMore User Manual Technical Appendices
21

22 7. Q. PLEASE GENERALLY DESCRIBE THE DSMORE MODELING TOOL
23 AND ITS DEVELOPER, IA.

24 A. The DSMore modeling tool is an award-winning modeling software that is
25 nationally recognized and has been used in 30 states to determine the cost-
26 effectiveness of energy efficiency and demand response programs. It calculates the
27

1 traditional California Standard Practice tests described in the California Standard
2 Practice Manual and is flexible enough to calculate jurisdictional specific tests and
3 many types of distributed energy resources projects and programs. The modeling
4 tool is developed and licensed by IA. IA also provides additional utility planning
5 software systems such as its LoadSEER distribution planning software which can
6 be integrated to DSMore. For over 20 years, IA has supplied cost-effectiveness
7 software, analytics, testimony and program planning, reconciliation, and evaluation
8 support for many leading U.S. utilities. Subject matter experts from IA have
9 testified in over 50 regulatory proceedings regarding over \$50B in energy savings
10 nationally for numerous utilities, public utility commission proceedings, and
11 stakeholder filings.

12
13 **8. Q. HOW DID IA USE DSMORE TO SUPPORT THE MPS AND**
14 **DETERMINATION OF DSM POTENTIAL?**

15 A. DSMore was used in the context of an integrated system planning framework that
16 can scale and improve over time. DSMore has features and functions that allow it
17 to better integrate with other tools and datasets for improved and more rapid
18 scenario analysis. For the MPS, DSMore was first calibrated to the Ace Guru model
19 so that DSMore was using the same source data for model inputs and the same
20 economic assumptions used in the Ace Guru model to ensure consistency. Inputs
21 into the model include participation rates, incentives paid, energy savings of the
22 measure, life of the measure, implementation costs, administrative costs, and any
23 incremental costs incurred by participants when installing an efficiency measure.
24 Energy savings for measures in both DSMore and Ace Guru were provided by
25 third-party independent evaluators. DSMore was setup to calculate the Non-energy
26 benefits Total Resource Cost test ("NTRC") used by NV Energy to test measures
27

and programs. IA supported model setup, calibration, and training in use of the model to NV Energy and support contractor Tierra Resource Consultants LLC (“Tierra”). IA supported use of the model to assess Economic, Maximum Achievable, and Realistically Achievable potentials for DSM measures. Although DSMore includes additional functions and options to improve the accuracy of the cost-effectiveness testing, these were not enabled in the integrated system planning modeling framework at this point in time. DSMore was used in the most similar fashion to the current use of Ace Guru with which stakeholders are familiar.

9. Q. HOW WAS DSMORE USED TO SUPPORT DSM AND DRP PLAN DEVELOPMENT?

A. DSMore was used to calculate the results of the six cost-effectiveness tests used by NV Energy for the DSM Plan to demonstrate to stakeholders that it can be setup to produce similar results to Ace Guru and could be relied upon as the going forward default tool after further stakeholder review and training. DSMore integrated with the Pathways model for the MPS technical potential and was used to calculate the MPS economic and achievable potential for DSM measures. DSMore was also used to calculate the cost-effectiveness of managed charging programs included in the Transportation Electrification Plan portion of the DRP.

10. Q. WHAT ARE THE SIMILARITIES AND DIFFERENCES BETWEEN ACE GURU AND DSMORE AND WHAT ARE KEY REASONS TO CHANGE THE DEFAULT MODEL FROM ACE GURU TO DSMORE?

A. Wherever possible, like Ace Guru, DSMore follows the precepts of the California Standard Practice Manual in the derivation of benefit-cost ratios and calculations. The California Manual was developed during the 1980s and 1990s, prior to the

1 advent of more powerful computing resources. The Standard Practice Manual is
2 recognized as the industry standard for determining cost-effectiveness and DSMore
3 follows the underlying procedures laid out in the manual. However, new methods
4 and new approaches to cost-effectiveness measurement have, and will, emerge
5 within the industry, given new processing capabilities, the advent of new microgrid
6 resources, and changes in marginal cost estimation. Software code in programming
7 language C# allows DSMore to be linked to the LoadSEER distribution planning
8 software and integrate more seamlessly with big data sources. Hundreds of
9 thousands of cost-effectiveness calculations are able to be run with actual AMI and
10 SCADA data, specific customer demographic data and utility location specific
11 avoided costs. Locational grid value can be identified for each local area,
12 substation, circuit or customer location and used in program planning to allocate
13 resources to specific needs.

14
15 Additionally, DSMore is designed to value the full range of potential integrated
16 demand side technologies including backup generation, local renewable generation,
17 electric vehicles, electrification, fuel switching, demand response, energy
18 efficiency and other disruptive technologies. As such, DSMore allows users to think
19 more broadly about the valuation of demand side resources than what is portrayed
20 in the California Manual and Ace Guru.

21
22 Unlike Ace Guru, DSMore explicitly measures the value of weather uncertainty on
23 program savings and avoided cost. The DSMore "Option Value" result takes into
24 account the "intrinsic value" of weather sensitive measures due to the flexibility
25 they provide in response to changes in weather. DSMore calculates
26 the intrinsic value from actual facility load shapes, regional energy prices and
27

weather covariance by measuring the impact and value of extreme weather variance. By retaining the full variance of program results as observed from historic data, DSMore is able to calculate the program impacts during extreme conditions and resulting actuarial or “insurance value” benefits. Ace Guru only retains the weather normal variance derived from the expected value of prices and savings, (the Standard Error) from a weather normalized deterministic simulation. Thus, the impact of extreme weather, price and measure savings are underrepresented. In the example table below, although the average energy prices (\$/kWh) may be consistent with historic observations, Ace Guru data significantly differs in the range, standard deviation and skew.

Annual Energy Price Distribution Statistics (\$/kWh)				
	2021	2022	2023	Used in Ace Guru for 2022
Average	52.00	87.41	76.04	59.13
Median	42.04	62.50	60.00	54.90
Skew	9.09	4.19	5.47	1.25
Min	5.00	3.57	-	0.01
Max	1,000	1,016	1,000	185
Stdev	53	93	58	24

11. Q. WAS THIS “OPTION VALUE” USED IN EITHER THE MPS OR IN DSM PLAN DEVELOPMENT?

A. The option value was not explicitly used or reported upon in the MPS or DSM plan filing as this method is new to key stakeholders and there was not enough time before the filing for stakeholder training on DSMore and more in-depth discussions about which methods or new benefits streams to formally include. However, in order to prepare for additional stakeholder engagement with respect to an examination of the impact of using market-based scenario inputs and option value calculations, IA and Tierra ran the full set of cost-effectiveness tests with this

method. Using this approach, energy efficiency programs at NV Energy generally had a 3 to 8 percent higher NTRC values, residential demand response programs generally had 9 to 16 percent higher NTRC values, and commercial demand response program NTRC values increased in the range of 9 to 30 percent. The option value is particularly useful for improving valuations for weather sensitive measures or load flexibility measures used to avoid high-cost hours.

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

A. Yes, it does.

EXHIBIT SKINNER-DIRECT-1

Statement of Qualifications

Kenneth Skinner

Professional Experience

2006 to date **Vice President, Program Design, Cost-Effectiveness and Risk**
Integral Analytics

Dr. Skinner has 25+ years of energy industry experience developing conservation, energy efficiency (EE), demand response (DR) and capacity supply strategies including cost-effectiveness (CE) analysis, integrated demand side management (IDSM) program design, potential assessment, measurement & verification (M&V) and risk assessment of least-cost portfolio opportunities. Co-developer of the award-winning efficiency cost-effectiveness software DSMore, and the location specific building assessment software Site-Optimizer, used in over 30 states by program administrators in program design and evaluation. Over 20 years, Integral Analytics Software has evaluated \$50B in energy savings nationally for numerous utilities, public utility commission proceedings, and stakeholder filings. Responsible for program cost-effectiveness calculations and risk assessment including program design, implementation support, reconciliation, evaluation and process calculations and guidance. Responsible for overall IDSM measure and program guidance and CE value assessment. A national expert in program design, valuation and impact verification, my goal is to assure our clients achieve mathematically accurate assessments of program value. Lead cost-effectiveness evaluator for utility energy efficiency and demand response programs from 2010 to 2022. Clients include IPL, Entergy, NV Energy, LG&E and KU and others. Provide Evaluation and Verification Services for utility energy efficiency and demand response programs from 2006 to 2022, including the development of M&V plans and evaluation activities for utility clients according to the International Performance Measurement and Verification Protocol's (IPMVP). Responsible for utility integrated demand side resource (IDER) project valuation. Using both grid value avoided cost and facility level customer value analytics, calculations include the joint grid and customer benefits of local distributed energy technologies, including efficiency,

Skinner-DIRECT

1

demand response, energy management, photo-voltaic, storage and electric vehicle charging. Evaluated the insurance or option value of the NV Energy auto demand response programs. Project involved reporting to the Nevada PUC, indicating a 60% increase in program value due to the insurance value of demand response as a risk contingency service.

Education

PhD, Colorado School of Mines, CO, 1999

MBA, Regis University, CO, 1986

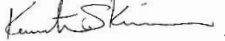
BS, Engineering, Letourneau University, TX, 1984

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

AFFIRMATION

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

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

Date: 5/31/2024 

Kenneth Skinner

MARIE STEELE

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05_____

Prepared Direct Testimony of

Marie Steele

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

A. My name is Marie Steele. My current position is Vice President, Integrated Energy Services, for Nevada Power Company d/b/a NV Energy (“NV 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 W. Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I am currently the Vice President of Integrated Energy Services (“IES”) at NV Energy. My roles in the Companies have spanned across transmission and distribution projects, financial planning and analysis, and renewable energy and origination at NV Energy.

As Principal and Co-Founder at e-Centricity, LLP, I co-authored the Nevada Governor’s Office of Energy report, Electrifying Nevada’s 21st Century Transportation System, Actions, Opportunities and Aspirations.

I received my Master of Business Administration from the ESADE Business School and my Bachelor of Business Administration in Finance from the University of Iowa.

The details of my background and experience are provided in **Exhibit Steele-Direct-1**.

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

A. As the Vice President of IES, I lead a diverse team responsible for the Companies' Demand Side Management ("DSM") Programs, Clean Energy ("CE") Programs, and various transportation electrification programs. The IES group is also responsible for distributed energy resource ("DER") planning and the Distributed Resource Plan ("DRP").

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

A. Yes, most recently, I testified in support of the Companies' Transportation Electrification Plan ("TEP") in Docket No. 22-09006 and the Companies' Economic Recovery Transportation Electrification Plan ("ERTEP") in Docket No. 21-09004. I also previously testified in support of the Companies' 2018 Application for Approval of the Annual Plan regarding the Solar Energy Systems Incentive Program, Wind Energy Systems Demonstration Program, the Waterpower Systems Demonstration Program, the Energy Storage and Low Income Components of the Solar Program, and the Electric Vehicle Infrastructure Demonstration Program for

Program Period 2018-2019, sponsoring the Companies' Annual Plan for approval of the Electric Vehicle Infrastructure Demonstration Program. I have also participated in multiple workshops.

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

A. The purpose of my testimony is to provide broad policy support for the DRP, and more specifically to support Section 2.A and 8.C within the DRP. My testimony also discusses the demand response, solar, and battery energy storage supply side resources within the Economic Analysis Section of the Supply Plan narrative sponsored by witness Kim Williams.

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

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

Exhibit Steele-Direct-1

7. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section I, I provide policy support of the DRP and sponsorship of Section 2.A DRP Goals and Strategies. In Section II I provide an overview of the DSM and DRP representation in the Supply Plan and the Economic Analysis as identified in Figure EA-8, DSM/DRP Programs Included in All Cases and Plans. In Section III, I sponsor the request for the approval of the Federal Funding Match ("FFM") resource size and types within Section 8.C of the DRP, the Pilot and Demonstration Projects or Programs.

**SECTION I: POLICY SUPPORT OF THE DRP AND SPONSORSHIP OF SECTION 2.A
DRP GOALS AND STRATEGIES**

STEELE-DIRECT

1 8. Q. WHAT EFFORTS HAS NV ENERGY MADE SINCE THE 2021 IRP TO
2 ADVANCE THE DIRECTIVES OF THE DRP?

3 A. The 2024 DRP filing sets forth a more focused strategy on integration of planning
4 and operations and harmonization of customer programs and benefits valuation.
5 The filing highlights progress to date and planned efforts to ensure a more
6 integrated organization, integrated planning processes and tools, integrated
7 operational systems, and more integrated rates and tariffs that more directly support
8 customer programs and DER adoption.
9

10 9. Q. HOW HAVE THOSE EFFORTS SUPORTED THE DEVELOPMENT OF
11 THIS IRP?

12 A. The Companies are evolving both the DRP and the DSM plans to ensure customer
13 programs and investments are providing incremental benefits through enabling
14 flexible load, to meet the growing constraints on the grid and economic growth of the
15 State.
16

17 The presentation of a new savings target in the DSM plan, the TEP within an IRP, and
18 a maturing DRP allows for new customer offerings, and technology advancements,
19 that create incremental value for all customers and the grid from policy-directed
20 customer programs that support the reduction of peak demand and system constraints,
21 enable electrification, and utilize excess renewable energy.
22
23

24 10. Q. WHAT ARE THE KEY NEXT STEPS WITHIN THE ACTION PLAN
25 PERIOD?
26
27

- A. Consistent with the “walk-jog-run” approach set forth in prior DRP filings, the Companies continue to advance their efforts with a focus on integration and harmonization themes. Key next steps include:
- Integrate approved customer programs within this IRP into the broader Non-Wires Alternative (“NWA”) solution set.
 - Further development and implementation of an integrated planning framework designed to allow iterative analysis of multiple potential future scenarios of DER adoption.
 - Further buildout of the DER Analytics Toolset to support the integrated planning framework with improved locational forecasting of DERs and potential associated locational benefits. This includes working with stakeholders to prioritize new benefits streams to include in the financial valuation of DSM programs and NWA opportunities.
 - Continued pursuit of federal funding opportunities along with the identification of new technologies, services, and program deployment approaches that support advancements of NWA opportunities cost-effectively coordinated with the DSM plan and supply-side efforts.
 - Strategic identification and pursuit of specific NWA opportunities along with expanded investigation of service and technology options available in the market.

SECTION II: DSM AND DRP INTEGRATION INTO THE SUPPLY PLAN

11. Q. PLEASE EXPLAIN THE DSM/DRP PROGRAMS INCLUDED IN ALL CASES AND PLANS AS REPRESENTED IN FIGURE EA-8 IN THE ECONOMIC ANALYSIS NARRATIVE.

A. In support of evolutions of the DSM and DRP, and as an advancement to demand side and distributed resource planning in this Joint IRP, the Companies introduced flexible load technologies and distributed resources as supply resources, rather than load modifiers. As such, these resources are shown in the L&R tables and are modeled in PLEXOS, as identified in the Economic Analysis. These resources are modeled the same in all cases and plans.

While there is a myriad of flexible load technologies, to introduce this new methodology, the Companies chose to model two different flexible load technologies. Air Conditioning Load Management (“ACLM”) is modeled as a fixed supply resource and Behind the Meter (“BTM”) Storage Demand Response is modeled with limited dispatchability. In future IRPs more specific NV Energy customer program technologies could be modeled individually and various technologies could participate in the economic analysis.

- ACLM is representative of the Companies’ existing, mature, air-conditioning demand side management demand response program.
- BTM Storage is representative of all other flexible load technologies, including batteries, presented in the DSM Proposed Grid Value plan and flexible load within the TEP. Flexible load within the TEP is representative of active managed charging programs and capacity from electric vehicle batteries, for example the expected availability of electric school bus

batteries within the action plan period from the implementation of the NV Energy Electric School Bus Vehicle to Grid Trial.

The small scale solar and battery energy storage systems within the plan are placeholders to support securing federal funding to advance various community solar initiatives with funding from the Environmental Protection Agency (“EPA”) Solar for All program that has since been awarded to Nevada Clean Energy Fund (“NCEF”).

- Utility-Owned Community Solar (“UOCS”) is a placeholder to be able to take advantage of NCEF Solar for All funds, that could buy down the cost of facilities that would expand upon NV Energy’s development of Community Based Solar Resources (“CBSR”) as part of the Companies’ Expanded Solar Access Program (“ESAP”) program.
- The Solar for All (“S4A”) Power Purchase Agreement (“PPA”) placeholders are related to a funding pathway that seeks to create a new low-income customer program(s) with funding from NCEF to reduce the cost of purchasing power from smaller scale solar plants with a maximize size of 5 MW each that could also be strategically developed and located to support grid operations.

Figure EA-8 describes those resources.

FIGURE EA-8
DSM/DRP PROGRAMS INCLUDED IN ALL CASES AND PLANS

Project Description	Technology	Company	Capacity (MW) ¹	Commercial Operation ²	Term (years)
ACLM	Demand Response	Nevada	Annual	In Operation	Ongoing
BTMS		Power/ Sierra	Growth	Beginning 2025	
UOCS	Solar PV/BESS ³	Nevada Power	14	6/1/2027	20
UOCS		Sierra	4	6/1/2027	20
UOCS		Nevada Power	11	6/1/2028	20
S4A PPA	Solar PV	Nevada Power	20	6/1/2027	20
S4A PPA	Solar PV	Sierra	10	6/1/2027	20

12. Q. WHERE IS THE REQUEST FOR THE ACLM DEMAND RESPONSE PROGRAM WITHIN THE IRP?

A. For the action plan period, the request is within the DSM Proposed Grid Portfolio Plan. Mr. Adam Grant sponsors the request.

13. Q. WHERE IS THE REQUEST FOR THE BTM STORAGE DEMAND RESPONSE PROGRAM?

¹ Each PV/BESS resource proposed in Figure EA-8 is 1:1 PV/BESS ratio.

² Commercial operation date as proposed.

³ BESS is modeled to be replaced after 10 years.

A. For the action plan period, the request is within the DSM Proposed Grid Portfolio Plan and the TEP, which is Section 10 of the DRP. Mr. Adam Grant sponsors both requests.

14. Q. WHERE IS THE REQUEST FOR THE UOCS AND S4A RESOURCES?

A. The request can be found in Section 8 of the DRP, Pilot and Demonstration Projects and Programs, subsection C, FFM Resources. I sponsor the request in the next section of this testimony.

15. Q. PLEASE EXPLAIN WHY THE RESOURCE SIZES FOR ACLM AND BTM STORAGE ARE NOT THE SAME IN THE SUPPLY PLAN AS IN THE DSM AND TEP ACTION PLAN PERIOD REQUESTS.

A. There are two main reasons for the difference in resource size. First, the resources in the supply plan were incorporated in the model in late 2023, prior to the Companies receiving their market potential study (“MPS”) and before the program design had begun. Therefore, the size of the demand response resources modeled were based off national studies, current market and economic conditions and the professional judgement of IES employees and contractors. Second, there are multiple scenarios and analyses for the DSM Plan, and there is only one resource per demand response type in the IRP. The Companies did not model different demand response resources for each DSM portfolio analysis performed.

16. Q. ARE THE ACLM AND BTM STORAGE DEMAND RESPONSE PROGRAMS BUDGETED WITHIN THE SUPPLY PLAN AND THE ASSOCIATED RATE IMPACT?

1 A. No. The financial requests and associated rate impacts for the ACLM and BTM
2 Storage Demand Response resources for the Action Plan Period are within the DSM
3 Plan and the TEP. The customer programs associated with those demand response
4 resource types are included in the DSM and TEP budgets and rate impact analyses.
5

6 **17. Q. ARE THE UOCS AND S4A RESOURCES BUDGETED WITHIN THE**
7 **SUPPLY PLAN AND THE ASSOCIATED OVERALL IRP RATE IMPACT?**

8 A. Yes.
9

10 **SECTION III: SPONSORSHIP OF SECTION 8.C PILOT AND DEMONSTRATION**
11 **PROJECTS AND PROGRAMS: FFM RESOURCES**
12

13 **18. Q. PLEASE DESCRIBE THE FFM RESOURCE REQUEST WITHIN THE**
14 **IRP.**

15 A. As described in Section II of my testimony, the Companies modeled both utility-
16 owned and PPA resources in expectation of NCEF being awarded EPA Solar for
17 All funding to advance existing and possibly create new low-income solar
18 program(s).
19

20 **19. Q. HAS THE NCEF APPLICATION TO THE EPA SOLAR FOR ALL BEEN**
21 **AWARDED FOR THE STATE OF NEVADA?**

22 A. Yes, however the award amount was lower than expected and the timing was later
23 than expected to be able to have more detailed information to present for
24 consideration within this IRP filing.
25

26 **20. Q. WHAT IS THE NEXT STEP FOR COLLABORATION WITH NCEF?**
27

A. NV Energy representatives will continue to work with NCEF through the summer to understand how the funding can support incremental CBSR development and the potential creation of a new customer program utilizing the S4A PPA resources within this IRP.

The Companies plan to seek new CBSRs starting in July of 2024 and will work with NCEF to understand available sites and costs, and how NCEF funding might support incremental CBSR development. Any updates would be filed in an amendment to the ESAP Implementation Plan.

NV Energy will also continue to work with NCEF on the availability of funding to create a new low-income customer solar program utilizing the S4A resources. The CBSR site nomination will help identify incremental site locations for this effort, especially to understand costs of the system(s).

21. Q. WILL THESE RESOURCES SUPPORT SYSTEM CONSTRAINTS AND IDENTIFIED NWAS?

A. Yes, when possible. The community engagement process to select CBSRs, and presumably, Solar For All funded resources, prohibits the Companies from utilizing these resources specifically for NWAs.

However, the Companies are proposing to pair the modeled BESS with the solar resources, if it is identified that it serves to remediate a system constraint identified with the NWAs. The current selection process for CBSRs ties to the Companies' NWA analyses in that one of the parameters is whether a potential site is within a

local area of the electric system where a constraint has been identified and so could potentially serve as a component of an NWA solution to the constraint.

22. Q. **WHAT IS THE GENERAL GOAL OF USING FEDERAL FUNDING FOR THESE RESOURCES?**

A. Generally, federal funding and incremental tax treatment can make these distributed resources more cost effective such that they align to utility scale levelized cost of energy, and the incremental cost is not subsidized by other customers.

Incrementally, these resources will support RPS compliance, resource adequacy, system constraints (where feasible), advance the implementation and development of distributed systems, and increase customer offerings for low-income customers.

23. Q. **WOULD THE NEW PROGRAM UTILIZING S4A RESOURCES BE A NET METERING PROGRAM?**

A. No. It would be a new program that provided savings to participating income-qualified NV Energy customers by meeting the requirements of the to be proposed program.

24. Q. **WHAT ARE THE COMPANIES REQUESTING OF THE COMMISSION REGARDING THE FFM RESOURCES?**

A. As of right now, the Companies request the Commission approve the resource type and size of the UOCS and S4A resources within this IRP, such that the Companies can return for further approval with resource costs and customer program requirements and/or design, where relevant, in the appropriate filings.

25. Q. HOW WOULD THE COMPANIES REQUEST FINAL APPROVAL OF THESE REQUESTS IF THE RESOURCE TYPE AND SIZE WERE APPROVED IN THIS IRP?

A. NV Energy will present further information, such as the awarding of funds to NV Energy and execution of contracts, in Annual DRP Update reports or appropriate ESAP filings, seeking further approval for the build of specific resource(s):

- Federal funding utilized to advance CBSRs will be brought forward in the appropriate ESAP filing, likely an amendment to the current Implementation Plan.
- If the Companies are granted the authority to utilize S4A resources to create a new program, the Companies will bring that forth for full approval within a DRP filing.
- If the Companies find that a BESS will support a grid constraint, or an identified NWA, the Companies will bring that forth for full approval within a DRP filing.

26. Q. WILL THE EPA SOLAR FOR ALL FUNDING AWARDED TO NCEF BE SUFFICIENT FOR ALL FFM RESOURCES PRESENTED IN THE PLAN? IF NOT, WHAT IS THE COMPANIES PROPOSAL?

A. Given the lower award amount to NCEF than expected, it is likely that the funding will not cover all FFM resources within this filing. However, the Companies request the approval of the full set of resource to allow the Company to seek additional federal funding opportunities with the Action Plan.

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27. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?
A. Yes.

STEELE-DIRECT

EXHIBIT STEELE-DIRECT-1

Marie K Steele

SUMMARY

Marie Steele is the Vice President of Electrification and Energy Services at NV Energy where she leads a diverse team responsible for the company's clean energy customer programs and services including energy efficiency, demand response, electric vehicles, battery storage and renewable energy. The team is also responsible for integrated grid planning and the distributed resource plan. Her experience at NV Energy spans across transmission and distribution projects, financial planning and analysis, and renewable energy strategy.

Marie received her MBA from the ESADE Business School in Barcelona, Spain and has Bachelor of Business Administration in Finance from the University of Iowa with an International Business Exchange at the University of New South Wales.

CHRONOLOGICAL EXPERIENCE

- Vice President, Electrification & Energy Services | NV Energy | 2021 – Present | Las Vegas
- Electrification Director | NV Energy | 2020 – 2021 | Las Vegas
- Principal and Co-Founder | E-Centricity, LLP | 2018 – 2019 | Las Vegas
- Electric Vehicle and Renewable Energy Manager | NV Energy | 2014 – 2018 | Las Vegas
- Business Analyst IV | NV Energy | 2012-2014 | Las Vegas
- MBA Intern | Quimera Responsible Racing | 2011 – 2011 | Barcelona, Spain
- Project Controls Manager | CH2M Hill | 2009 – 2009 | Abu Dhabi, United Arab Emirates
- Lead Project Controls Engineer | Analysts International | 2008 – 2008 | Las Vegas
- Sr Project Controls Engineer | Analysts International | 2006-2007 | Las Vegas
- Project Controls Engineer II | Bechtel Corporation | 2005 – 2006 | Chicago
- Project Controls Engineer I | Bechtel Corporation | 2004 - 2005 | Las Vegas

EDUCATION

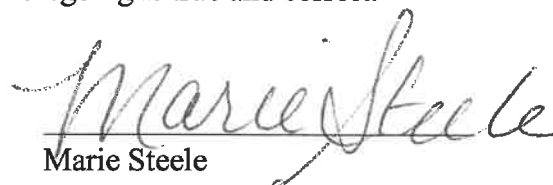
- Master Business Administration | 2012 | ESADE Business School | Barcelona, Spain
- Bachelor Business Administration | 2004 | University of Iowa | Iowa City, IA, USA

AFFIRMATION

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

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

Date: May 31, 2024


Marie Steele

JOSEPH V SINOBIO

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05_____

Prepared Direct Testimony of

Joseph V. Sinobio

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

A. My name is Joseph V. Sinobio. I am the Director of Integrated Grid 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 6226 W. Sahara Ave. 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 continuously employed by NV Energy since September 1988. I have experience in electric utility transmission and distribution planning, and distributed energy resources (“DERs”). I have a Bachelor of Engineering degree in electrical engineering. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Sinobio-Direct-1**.

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

3 A. As Director of Integrated Grid Planning, my responsibilities include supporting
4 DER planning, interconnection, impact studies, Hosting Capacity Analysis
5 (“HCA”), Grid Needs Assessment (“GNA”) analysis, Non-Wires Alternative
6 (“NWA”) analysis, and Locational Net Benefits Analysis (“LNBA”) on the
7 Companies’ distribution systems. I have overall responsibility for ensuring delivery
8 of the Companies’ Distributed Resources Plan (“DRP”).
9

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

13 A. Yes. I have provided written testimony and also appeared before the Commission
14 in various dockets, most recently, the application by the Companies seeking
15 Commission approval of their 2021 Joint Integrated Resource Plan (“IRP”) (Docket
16 No. 21-06001), their 2022 Joint DRP Update (Docket No. 22-09001), and their
17 2023 Joint DRP Update (Docket No. 23-09002). I have also participated in
18 Commission workshops in various investigatory dockets.
19

20 **5. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY**
21 **IN THIS CASE?**

22 A. My testimony is in support of certain sections of the 2024 DRP (“DRP”) narrative,
23 specifically:

- 24 • Section 1 – Executive Summary;
 - 25 • Section 2 – Introduction (all sections except 2.A);
- 26
27

- Section 3.A – Distributed Resources Plan Analyses; Distribution Planning and Integrated Grid Planning;
- Section 4 – Barriers to Deployment of Distributed Energy Resources;
- Section 6 – Publicly-Accessible DRP Web Portal;
- Section 7.C – Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Energy Resources; DER Analytics Toolset and Potential Study;
- Section 8.A.1 – Pilot and Demonstration Projects; Non-Wires Alternative Analysis; Mt. Charleston Microgrid Investigation.
- Section 9 – Continued Refinement of DRP Elements and View Moving Forward;
- Section 11 – Specific Requests for Commission Approval; and
- Technical Appendices DRP-1 through DRP-4, DRP-7, and DRP-10.

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

A. I am sponsoring **Exhibit Sinobio-Direct-1** and **Technical Appendices DRP-1 through DRP-4, DRP-7, and DRP-10.**

7. Q. ARE OTHER NV ENERGY WITNESSES SUPPORTING OTHER SECTIONS OF THE DRP NARRATIVE?

A. Yes. Specifically, Marie Steele is supporting Sections 2.A and 8.C, Tyler Meroth is supporting Section 3.B, Kimberly Williams is supporting Section 5.A, Patricia Rodriguez is supporting Section 5.B and Technical Appendices DRP-8 and DRP-9, Michael Brown is supporting Sections 7.A, 7.B, 8.A.2, and 8.B, and Adam Grant is supporting Section 10 (which is NV Energy’s Transportation Electrification Plan (“TEP”)) and Technical Appendices TEP-1 through TEP-6.

Also, Mr. Snuller Price of Energy and Environmental Economics, Inc. (“E3”) is supporting Technical Appendices DRP-5 and DRP-6.

8. Q. PLEASE DESCRIBE YOUR ROLE IN PREPARING THIS DRP.

A. I oversaw the drafting of the DRP narrative, with the exception of sections supported by other NV Energy witnesses, ensuring its adherence to all applicable regulatory and legislative requirements and its timely completion. Specifically, I oversaw the completion of the technical analyses of NV Energy’s distribution systems for the DRP and the recommendations based on those analyses. I was responsible for:

1. Acquiring the distribution load and DER forecasts at the substation and distribution feeder levels;
2. Directing completion of the HCA studies, GNA, NWA analyses, and LNBA on the Companies’ distribution systems;
3. Developing NV Energy’s plan to refine several elements of the DRP;
4. Recommending any traditional distribution wired capital upgrade projects, NWA solutions, and certain pilots and demonstration projects on the Companies’ distribution systems; and
5. Compiling certain specific requests for Commission approval and requests for deviations from Nevada Administrative Code (“NAC”) regulations.

9. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF THE DRP NARRATIVE SECTIONS THAT YOU ARE SUPPORTING IN THIS FILING.

A. **Section 1 – Executive Summary** provides an overview of the contents in the DRP narrative.

Section 2 – *Introduction* provides details as follows:

1. *Overview of DRP Contents* outlines the contents of the DRP;
2. *Legislative and Regulatory Requirements* lists statutory and regulatory authorities applicable to a DRP;
3. *Stakeholder Engagement* provides details on the robust stakeholder engagement process that NV Energy utilized in developing its DRP;
4. *DG Penetration on NV Energy's Grid* provides information on the level of DG penetration at the system level and on the highest penetrated distribution feeders;
5. *Effect of NEM Systems on Distribution System Reliability* discusses how net energy metering ("NEM") systems could affect the reliability of the distribution system; and
6. *Definitions and Acronyms* provides definitions of technical terms and explains any of the narrative's acronyms.

Section 3.A – *Distributed Resources Plan Analyses; Distribution Planning and Integrated Grid Planning* describes the Companies' activities, processes, and analyses on the distribution system in support of the DRP in the following areas:

1. *Load and DER Forecasting* describes generally how load forecasting is performed at the distribution feeder level for the Companies, discusses the effect of DERs on distribution load forecasting, and discusses DER forecasting;
2. *Hosting Capacity Analysis* describes how the distribution substation and feeder models were prepared utilizing the Companies' Synergi Electric distribution power flow software, how the loading profile data for the Companies' distribution feeders was developed, the analytical method for

the HCA, the results of the HCA, and a discussion of “real-time” hosting capacity and NV Energy’s progress in that regard; and

3. *Grid Needs Assessment – 2024 Capital Plan* describes how the Companies identified existing and forecasted constraints on their distribution systems for the years 2025 through 2030, the identifying information and parameters of those constraints in terms of the deficiencies involved, the identified traditional distribution wired capital upgrade solutions for addressing those constraints, the Companies’ NWA Suitability/Screening Criteria to determine which of the identified constraints could be suitable for a potential NWA solution, the method and the NWA Screening Analysis Tool that the Companies used to perform the NWA analyses, the results of the NWA analyses, including the sizing of the DER technologies (demand response, energy efficiency, conservation voltage reduction, solar photovoltaic, and battery energy storage) used in the potential NWA portfolio, the Present Worth of Revenue Requirements (“PWRR”) analyses that were performed by the Companies comparing the costs of traditional wired capital upgrade solutions against the costs and potential system-level and locational benefits of NWA solutions, and lists the traditional distribution wired capital upgrade solutions and the NWA solutions that the Companies recommend to address the identified constraints on the distribution system.

Section 4 – *Barriers to Deployment of DER* describes the barriers that NV Energy identified that would be a deterrent to the deployment of DERs and the solutions to remove those barriers.

Section 6 – *Publicly Accessible DRP Web Portal* discusses the web portal that NV Energy developed to share the outputs from the DRP analyses with the public.

Section 7.C – *Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Energy Resources; DER Analytics Toolset and Potential Study* briefly describes the Companies’ DER Analytics Toolset and Potential Study effort.

Section 8.A.1 – *Pilot and Demonstration Projects and Programs; Non-Wires Alternative Analysis; Mt. Charleston Microgrid Investigation* briefly describes the Companies’ investigation into potentially implementing a non-wires microgrid solution to mitigate service risk in lieu of traditional wired capital upgrade solutions in the Mt. Charleston area.

Section 9 – *Continued Refinement of DRP Elements and View Moving Forward* describes the Companies’ present plans to further refine the methods and tools used in performing the various analyses required to develop the DRP over the next several years and an overview of where the efforts associated with the DRP sit with respect to the “walk-jog-run” philosophy employed by the Companies to evolve the DRP.

Section 11 – *Specific Requests for Commission Approval* describes any specific requests that the Companies are making of the Commission in this DRP, including requests for the Commission’s approval of various elements of the DRP, any specific projects that the Companies may be seeking approval for, and any variances requested by the Companies from the requirements in NAC.

Technical Appendix DRP-1 contains the initial list of issues gleaned from intervenor testimony in Docket No. 21-06001 that served as discussion points for the DRP stakeholder discussion process that took place between December 2022 and February 2024 and notes related to each of the issues.

Technical Appendix DRP-2 contains the meeting notes from seven DRP stakeholder meetings held between December 2022 and February 2024 taken by NV Energy and provided to stakeholders.

Technical Appendix DRP-3 contains distribution substation transformer and distribution feeder past peak loads from 2019 to 2023 for both Nevada Power and Sierra.

Technical Appendix DRP-4 contains distribution substation transformer and distribution feeder forecasted peak loads as of March 10, 2024, for 2024 to 2030 for both Nevada Power and Sierra.

Technical Appendix DRP-7 contains a flowchart of NV Energy's HCA monthly update process.

Technical Appendix DRP-10 contains NV Energy's DRP web portal user guide.

10. Q. IS NV ENERGY MAKING ANY SPECIFIC REQUESTS OF THE COMMISSION IN THIS DRP?

A. Yes.

11. Q. WHICH SPECIFIC REQUESTS OF THE COMMISSION ARE YOU SUPPORTING IN THIS TESTIMONY?

A. Section 11.A of the DRP narrative describes the Companies' requests for the Commission. Specifically, I support NV Energy's request for the Commission to find that the elements contained in the DRP continue to be prudent and for Commission approval of the 2024 DRP as compliant with NAC 704.9237, including the following:

1. The summary describing the results of the February 5, 2024, stakeholder meeting discussed in Section 2.D.1 is in compliance with NAC 704.9237(3)(e);
2. The summary of the effects of NEM on the reliability of the distribution system discussed in Section 2.F is in compliance with NRS 704.741(3)(d);
3. NV Energy's load and DER forecasting methods as discussed in Section 3.A.1 is in compliance with NAC 704.9237(2)(f);
4. NV Energy's HCA methods as discussed in Section 3.A.2 are in compliance with NAC 704.9237(3)(b);
5. NV Energy's GNA methods as discussed in Section 3.A.3, including the identification of distribution constraints and projects in Section 3.A.3.a, the NWA analyses in Section 3.A.3.b, the LNBA in Section 3.A.3.c, and the traditional wired upgrade projects and NWA solutions recommendations in Section 3.A.3.d, are in compliance with NAC 704.9237(2)(a), 704.9237(3)(a), and 704.9237(3)(c);
6. The identification of barriers to the deployment of DERs discussed in Section 4 is in compliance with NAC 704.9237(2)(e);

7. The development, deployment, and updating of a publicly accessible Web Portal that provides maps and accessible electronic data discussed in Section 6 are in compliance with NAC 704.9237(5);
8. The identification of incremental investment in tools, systems, or technologies to integrate DERs in Section 7.C is in compliance with Nevada Administrative Code (“NAC”) 704.9237(2)(d); and
9. Technical Appendices DRP-1 through DRP-4, DRP-7, and DRP-10 comply with NAC 704.9237(3)(f).

I also support NV Energy’s request for the Commission to find that the Companies have complied with Directive 15 from Docket No. 21-06001.

12. Q. WHICH SPECIFIC REQUESTS OF THE COMMISSION ARE OTHER NV ENERGY WITNESSES SUPPORTING IN THEIR TESTIMONY?

A. Mr. Meroth is supporting the Companies’ request for the Commission to approve Section 3.B as prudent and in compliance with applicable subsections of NAC 704.9237.

Ms. Williams is supporting the Companies’ request for the Commission to approve Section 5.A as in compliance with NAC 704.9237(3)(d).

Ms. Rodriguez is supporting the Companies’ request for the Commission to approve Section 5.B as in compliance with NAC 704.9237(2)(c), that Technical Appendices DRP-8 and DRP-9 comply with NAC 704.9237(3)(f), and to find that the Companies complied with Directives 4, 5, and 6 of Docket No. 23-02001.

Mr. Brown is supporting the Companies' request for the Commission to approve Sections 7.A and 7.B as in compliance with NAC 704.9237(2)(d) and \$300,000 to investigate and develop an NWA Tariffed-On-Bill Pilot.

Mr. Grant is supporting the Companies' request for the Commission to approve Section 10 (NV energy's TEP) as in compliance with NAC 704.9237(3)(g) and Technical Appendices TEP-1 through TEP-6 comply with NAC 704.9237(3)(f).

Ms. Steele is supporting the Companies' request for conditional approval of the Utility Owned Community Solar and Solar for All fixed supply-side placeholder resources within the DRP program resources.

13. Q. PLEASE DESCRIBE HOW NV ENERGY UTILIZED THE LOAD AND DER FORECASTS EMPLOYED IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES COMPLIANT.

A. NAC 704.9237(2)(f) states that the DRP must:

Be developed by a utility using a forecast of net distribution system load and distributed resources. The forecast must be for a period of not less than 6 years, beginning with the year after the distributed resources plan is filed. The net distribution system load and distributed resources forecast will include system, substation and feeder level net load projections and energy and demand characteristics for all distributed resource types.

As stated in Section 3.A.1.a of the DRP narrative, NV Energy utilized the latest available load forecasts for distribution substation transformers and distribution feeders at the time analyses were performed, which supported the determination of constraints on the distribution system and the consequent traditional wired upgrade

projects (solutions). The load forecasts covered the minimum six-year timeframe following the year of the filing of this DRP.

The above activities meet the requirements of NAC 704.9237(2)(f) with one exception, which is noted in Section 11.B of the DRP narrative. NV Energy is requesting a waiver of the portion of NAC 704.9237(2)(f) that requires:

The net distribution system load and distributed resource forecast will include system, substation, and feeder level net load projections and energy and demand characteristics for all distributed resource types.

As noted in Section 11.B, NV Energy’s consultant Energy and Environmental Economics, Inc. (“E3”), produced geolocational forecasts for DERs at the census block level and the Companies translated some of that data (EE, DR, and solar photovoltaic results for 2034) to its distribution feeders and incorporated it into the NWA analyses. As noted in Section 9.A of the DRP narrative, NV Energy will integrate the results from E3’s analysis for all DER types into its planning, forecasting, and analyses associated with the DRP as appropriate over the next year ahead of the planned filing of an update to the DRP on or before September 1, 2025, to close this compliance gap. The results from the DRP analyses were not appreciably diminished due to this gap in forecast data.

14. Q. PLEASE DESCRIBE NV ENERGY’S ACTIVITIES REGARDING HCA IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES COMPLIANT.

A. As stated in Section 3.A.2 of the DRP narrative, since the Companies’ filing of the 2021 DRP, NV Energy performed its HCA using load flow analyses on models of the Companies’ distribution systems via the Synergi Electric power flow software.

NV Energy completed HCA on more than 1,300 distribution feeders three times since the filing of the 2021 DRP in a process spanning the first quarters of 2022, 2023 and 2024. Also since the filing of the 2021 DRP, NV Energy completed updating the hosting capacity of selected feeders monthly in October through December 2021, April through December 2022, and August through December 2023. As noted in Section 3.A.2, the Companies were unable to complete their normal monthly hosting capacity update process in April through August 2023 due to an Information Technology security issue that did not allow use of the Synergi software during those months but were able to resume this process in August 2023.

The DRP narrative provides a detailed description of the methods and outcomes of the HCA, discusses the Companies' publicly-accessible Web Portal to view the HCA results with downloadable electronic data, and provides a narrative describing the Companies' methods in providing publicly-available "real-time" hosting capacity results updated on a monthly basis. These activities, as described in the DRP narrative, meet the requirements of NAC 704.9237(3)(b), with the exception noted below.

As noted in Section 11.B of the DRP narrative, NV Energy is requesting a waiver of the portion of NAC 704.9237(3)(b) which requires that the DRP must include an HCA of the distribution system evaluated "*under normal conditions and planned and unplanned contingency conditions.*" NV Energy completed the HCA for this DRP under normal system operating conditions, but not under planned or unplanned contingency conditions. The Companies have begun discussing the issue of performing HCA under contingency conditions internally and initially concluded that any contingencies analyzed would need to be limited in scope to ensure that

the number of cases analyzed do not create an untenable situation in terms of being able to complete the analysis, especially considering that the monthly update and annual full-system update processes already take an entire month and an entire quarter to be completed, respectively, with current processes and resources. NV Energy also is investigating how other utilities may be approaching this issue to ascertain if there are any techniques that can be applied to ensure that the analytical process would not be overburdened by the addition of contingency conditions. The unavailability of HCA results under contingency conditions does not compromise other analyses in the filing, nor does it have an appreciable effect on or diminish the usefulness of this DRP.

15. Q. PLEASE DESCRIBE NV ENERGY'S ACTIVITIES REGARDING THE GNA FOR THE COMPANIES' DISTRIBUTION SYSTEMS IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES COMPLIANT.

A. As described in Section 3.A.3 of the DRP narrative, NV Energy developed its GNA on its distribution system including a HCA, NWA analyses, an LNBA, which compares utility infrastructure wired upgrade solutions and DER solutions to forecasted distribution constraints, and recommendations for traditional wired upgrade projects and NWA solutions. These activities, as described in the DRP narrative, meet the requirements of NAC 704.9237(2)(a), 704.9237(3)(a), and 704.9237(3)(c).

16. Q. PLEASE DESCRIBE NV ENERGY'S ACTIVITIES REGARDING IDENTIFICATION OF BARRIERS TO THE DEPLOYMENT OF DERs IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES COMPLIANT.

A. Section 4 of the DRP narrative identifies potential barriers to the deployment of DERs grouped into three categories: (1) integration/interconnection of DERs with the distribution grid, (2) market limitations on the ability of DERs to deliver promised benefits, and (3) distribution system operational and infrastructure capability to handle DER value. The Companies also present some potential solutions that could address these barriers and the status of related activities. These activities, as described in the DRP narrative, meet the requirements of NAC 704.9237(2)(e).

17. Q. PLEASE DESCRIBE NV ENERGY'S ACTIVITIES REGARDING DEVELOPMENT AND DEPLOYMENT OF A PUBLICLY ACCESSIBLE WEB PORTAL IN THIS DRP AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES COMPLIANT.

A. Section 6 of the DRP narrative discusses the publicly accessible DRP web portal and any updates to it. These activities, as described in the DRP narrative, meet the requirements of NAC 704.9237(5).

18. Q. PLEASE DESCRIBE NV ENERGY'S ACTIVITIES REGARDING DIRECTIVE 15 FROM DOCKET NO. 21-06001 AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES COMPLIANT WITH THE DIRECTIVE.

A. Directive 15 from Docket 21-06001 required NV Energy to “convene a stakeholder process to consider and address” concerns identified in the testimony of certain interveners in that docket.¹ Section 2.D.2 of the DRP narrative and Technical Appendices DRP-1 and DRP-2 outline NV Energy’s activities to comply with the directive. In accordance with the directive, NV Energy convened stakeholder meetings within 365 days of the issuance of the order in that docket. The Companies collected the pertinent concerns from intervenors in that docket and used that list (provided in Technical Appendix DRP-1) as the basis for discussion in the seven meetings that took place between December 2022 and February 2024. NV Energy also compiled running notes of the meetings that were provided to stakeholders within each of the meeting notices (provided in Technical Appendix DRP-2).

As evidenced by the above, NV Energy has complied with Directive 15.

19. Q. ARE SECTIONS 8 AND 9 OF THE DRP NARRATIVE REQUIRED BY THE DRP REGULATIONS?

A. No.

20. Q. WHY ARE SECTIONS 8 AND 9 OF THE DRP NARRATIVE INCLUDED AND WHAT PURPOSE DO THEY SERVE?

A. Although some of the concepts associated with the DRP have been progressing and maturing in other states and in Nevada, NV Energy believes that it may be prudent to pilot or demonstrate certain concepts, methods, or technologies prior to a decision to employ them in the first place, how to employ them, or whether to apply

¹ Docket No. 21-06001, March 8, 2022, Corrected Modified Final Order at 179, para. 15.

or deploy them system wide. Section 8 captures any activities or recommendations in this regard. Of particular note is NV Energy's proposed investigation into a NWA Tariffed-on-Bill Pilot that is supported by NV Energy witness Mr. Brown.

Section 9 describes the Companies' present expectations to further refine the methods and tools used in performing the various analyses required to develop the DRP. NV Energy has continued to employ a prudent "walk-jog-run" approach to developing and maturing the methods and analyses required to support the goals of the DRP. Although NV Energy's first DRP was filed with the Commission five years ago in April 2019, this 2024 DRP is representative of the still-emerging nature of this industry in the state and should be expected to continue to change in the coming years. In Section 9, NV Energy lays out the progression of several main elements of the DRP through the next several years.

Finally, this section serves to illuminate the "walk-jog-run" approach by clarifying the activities associated with each level, thereby cultivating an understanding of where within this model the various DRP activities presently reside and how they may progress. A status of the present "jog" activities is also provided.

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

A. Yes, it does.

EXHIBIT SINOBIO-DIRECT-1

**Statement of Qualifications
for
JOSEPH V. SINOBIO**

Summary of Qualifications

Over 35 years of electric utility experience, including 30 years of leadership experience, all for NV Energy (Nevada Power Company and Sierra Pacific Power Company) based in Las Vegas, Nevada. Experienced in electric utility distribution planning, distributed energy resources, interconnection, impact studies, and integrated grid planning. Experienced in management and leadership techniques, goal-setting, process analysis, capital budgeting, technical writing, and providing regulatory testimony.

Professional Experience

<i>Director, Integrated Grid Planning</i>	September 2023 – Present
<i>Integrated Grid Planning Manager</i>	November 2020 – September 2023
<i>Manager, Major Projects-Delivery</i>	June 2016 – November 2020
Nevada Power Company and Sierra Pacific Power Company (d/b/a NV Energy)	

Directly manage a team responsible for supporting distributed energy resource planning, interconnection, and impact studies, and integrated grid planning including Hosting Capacity Analysis and Non-Wires Alternative Analysis. Overall responsibility to ensure delivery of the Distributed Resources Plan.

<i>Manager, Distribution Planning</i>	January 2005 – June 2016
Nevada Power Company and Sierra Pacific Power Company (d/b/a NV Energy)	

Directly managed a team responsible for the regional electric Distribution Planning function.

<i>Director, Distribution Technical Services</i>	March 2001 – January 2005
Nevada Power Company and Sierra Pacific Power Company	

Directed a team responsible for the regional Distribution Standards, electric Distribution Planning (34.5 kV and below), Central Mapping, and Distribution Operations Technical Support functions.

<i>Manager, Regional Electric Technical Services</i>	May 2000 – March 2001
Nevada Power Company and Sierra Pacific Power Company	

Managed a team responsible for the regional electric Distribution Planning, Central Mapping, and the Distribution Operations Technical Support functions.

<i>Manager, Regional Electric Distribution Planning</i>	September 1999 - May 2000
Nevada Power Company and Sierra Pacific Power Company	

Directly managed a team responsible for the regional electric Distribution Planning and Distribution Operations Technical Support.

Manager, Distribution Planning & Analysis

January 1998 – September 1999

Nevada Power Company

Directly managed a Distribution Planning team.

Manager, Distribution Planning, Standards & Analysis

January 1994 – January 1998

Nevada Power Company

Managed a Distribution Planning and Distribution Standards team.

Engineer II - III, Transmission Planning

July 1991 – January 1994

Nevada Power Company

Performed detailed engineering analysis to recommend transmission system capital improvement projects, transmission construction requirements for new load additions, and system transfer capability using WSCC powerflow software. Improved departmental analysis procedures by developing a transmission master plan for the southern Las Vegas Valley (+100 square mile area).

Engineer I - II, Distribution Planning

April 1989 – July 1991

Nevada Power Company

Performed engineering analysis in developing distribution master plans, distribution load forecasts, and in recommending distribution system capital improvement projects, distribution construction requirements for new load additions, and new distribution feeder and substation additions for the northern and western Las Vegas Valley (+200 square mile area with an average annual growth rate of approximately 5%).

Training, Education, & Memberships

Leadership Development Program; Supervisor's Workshop; Team Building; Lessons in Leadership; Change Management; Project Management; Finance & Accounting for Non-Financial Managers; Management Accounting; Managing Multiple Projects, Objectives & Deadlines; Media Training; Customer Relations Training; Situational Leadership II; Criticism & Discipline Techniques for Managers, Mutual Gains; Seven Management & Planning Tools; Managers and Supervisors Conference; Utility Finance & Accounting; Replacing Negativity with Enthusiasm; Coaching Skills for Managers & Supervisors; 7 Habits Fundamentals Workshop; Spatial Load Forecasting; Assertive Leadership Skills; The 4 Disciplines of Execution; Creative Leadership Workshop.

Bachelor of Engineering Degree in Electrical Engineering; State University of New York; Stony Brook, NY; 1988.

I.E.E.E. Power & Energy Society Member

AFFIRMATION

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

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

Date: May 31, 2024


JOSEPH V. SINOBI

MICHAEL O BROWN

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05_____

Prepared Direct Testimony of

Michael O. Brown

SECTION I: INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. My name is Michael O. Brown. My job title is Integrated Energy Services Director 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 W. Sahara Ave. Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I have more than 25 years of experience in energy efficiency, renewable energy, demand response (“DR”), distributed energy resources (“DERs”), dynamic pricing, and advanced meter and smart grid infrastructure in a variety of roles. I have been continuously employed by NV Energy since September 2005, working in the Demand Side Management (“DSM”), Renewable Energy and Origination, and Integrated Energy Services departments focused on building out integrated energy efficiency and DR programs and related infrastructure and services. I have

supported major projects such as the statewide advanced meter infrastructure deployment and the Nevada Dynamic Pricing Trial. I have a Bachelor of Science degree in chemistry and international relations as well as a Master of Business Administration. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Brown-Direct-1**.

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

A. I provide leadership and strategic direction to cross functional planning and operations teams in the Integrated Energy Services department. I also provide business oversight of the development of and implementation of DSM, DR and DER operations and planning software and DSM and Distributed Resource Plan (“DRP”) related pilot projects, demonstrations, and trials.

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

A. Yes. I have provided written testimony and also appeared before the Commission in various dockets including, more recently, the 2023 Joint DRP Update (Docket No. 23-09002), 2022 Joint DRP Update (Docket No. 22-09001) and the application by the Companies seeking Commission approval of their 2021 Joint Integrated Resource Plan (“IRP”) (Docket No. 21-06001), in which NV Energy’s second Distributed Resources Plan (“2021 DRP”) was filed. I have also participated in Commission workshops in various investigatory dockets.

5. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY
IN THIS CASE AND HOW IS YOUR TESTIMONY ORGANIZED?

A. Section II of my testimony is in support of Sections 7.A, 7.B, 8.A.2, and 8.B of the 2024 DRP narrative, entitled “Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Energy Resources; Distributed Energy Resource Management System; and Department of Energy Grid Services Grant Project” and “Pilot and Demonstration Projects; Non-Wires Alternative Tariffed-On-Bill Pilot; and Locational Net Benefits Analysis.” In Section III of my testimony, I support Section 3 Overview of the Financial Models of the DSM narrative and explain the Companies’ intention to change the default cost-effectiveness model from Ace Guru to DSMore at a future date, after further review of DSMore by stakeholders.

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

A. I am sponsoring **Exhibit Brown-Direct-1**.

SECTION II: DISTRIBUTED RESOURCE PLAN NARRATIVE SUPPORT

7. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF THE DRP
NARRATIVE SECTIONS THAT YOU ARE SUPPORTING IN THIS
FILING.

A. **Sections 7.A and 7.B** – *Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Energy Resources; Distributed Energy Resource Management System; and Department of Energy Grid Services Grant Project* provide updates on two projects that were approved by the Commission in the 2021 DRP filing in Docket No. 21-06001. The first project update focuses on the status of the capital project to build a Distributed Energy Resource Management System

(“DERMS”). The second update focuses on NV Energy’s participation in a United States Department of Energy (“DOE”) funded cooperative agreement referred to as the DOE Grid Services Set (“GSS”) Grant project.

The DOE GSS Grant is a collaborative project. The project team includes the University of Nevada, Reno (“UNR”), University of Nevada, Las Vegas (“UNLV”), and a private software development company Evolution Networks (collectively, including NV Energy, the “Project Team”). The DOE is funding research, software development, and field demonstration of novel services from aggregated DERs. In addition to the cost share required under the cooperative agreement, NV Energy installed a 1-megawatt/4-megawatt-hour battery energy storage system (“BESS”) at its Beltway Substation in Las Vegas to support testing of the software and services developed under the cooperative agreement.

Section 8.A.2 – Pilot and Demonstration Projects; Non-Wires Alternative Tariffed-On-Bill Pilot proposes a phase-gated effort to evaluate at the Companies a new utility financing approach. The first phase of the pilot proposes a budget of \$300,000 to fund development efforts with a strong focus on working with stakeholders to flesh out the details of such an offering in Nevada along with a specific field demonstration proposal. Then, if that effort is successful, the more detailed plans for the service offering and field demonstration in areas identified as high potential for non-wires alternative (“NWA”) solutions would be filed in an Annual DRP Update report.

Section 8.B – Pilot and Demonstration Projects; Locational Net Benefits Analysis refers to NV Energy’s present efforts in its DOE GSS Grant project to implement

a field demonstration to evaluate the capability of DER aggregations to provide locational net benefits and support NWAs.

8. Q. PLEASE DESCRIBE NV ENERGY’S RECENT ACTIVITIES REGARDING THE DEVELOPMENT AND DEPLOYMENT OF DERMS.

A. NV Energy has contracted with Oracle Utilities (collectively, the “Parties”) to build a “system of systems” DERMS. This means that Oracle will integrate several software systems to deliver an overall solution that meets the contracted functional requirements for DERMS.

The Parties planned a multiple software release strategy in which prioritized functionality is delivered and moved into production first and subsequent releases continue to add incremental functionality. The first release was completed and moved into production on May 22, 2023. This release improved the speed and security of communications with DER devices in the field using the Oracle Live Energy Connect software product.

The Parties have developed plans for future releases that extend over a longer time frame than originally expected due to three primary factors: 1) the deployment of Oracle’s Advanced Distribution Management System (“Oracle NMS”) at NV Energy was pushed back to the 2027 timeframe; 2) design workshops and security reviews revealed the need for an additional external system to support security related to aggregated DERs; and, 3) changes required to the Oracle product suite to handle the complex DERMS functional requirements within the system of systems approach are more complex and extensive than originally estimated.

Yearly releases are planned for 2025 - 2028, with each release bringing new functionality. This new plan assumes Oracle NMS is deployed at NV Energy starting in 2027. Due to the longer timeframe to carry project resources and need to supplement DER control with an external system, the budget estimate has risen from the originally approved \$15,482,578 filed in Docket No. 21-06001 to \$24,829,779. As more firm information is determined related to contracts, incremental cost, and schedule, NV Energy will present it in the Annual DRP Update Report along with a refresh of the DERMS business case financial calculations.

9. Q. PLEASE DESCRIBE NV ENERGY'S RECENT ACTIVITIES REGARDING ITS PARTICIPATION IN THE DOE GRID SERVICES GRANT PROJECT.

A. The DOE GSS Grant project is divided into three major phases referred to as Budget Periods. The first two Budget Periods had specific deliverables that had to be completed and accepted by DOE before authorization to proceed into the next phase. The Project Team completed the Budget Period 1 research phase of the project on January 31, 2022, and completed the Budget Period 2 development phase of the project at the end of 2023. The Project Team is now working on Budget Period 3 which is planned to be completed by the end of July 2024. Budget Period 3 focuses on deploying a field demonstration to test new approaches to recruit customers into bundled DER service offerings that would allow NV Energy to create a localized DER aggregation to provide grid services. The field demonstration will include operational research by UNR and UNLV to evaluate the performance of the developed software services, and independent measurement and verification of the capability of the DER aggregation to effectively reduce local

feeder and substation loadings. UNR will simulate the capability of much larger DER aggregations to support distribution feeder voltages. Due to cost share increases from the Project Team, NV Energy expects the final total budget to climb by 5% from an original budget of \$3,981,689 to \$4,179,661.

10. Q. PLEASE DESCRIBE NV ENERGY'S PROPOSED NWA TARIFFED-ON-BILL PILOT.

A. The pilot is proposed as a phase-gated effort to investigate, develop, and test a financing approach that has been deployed at other utilities as an option for customers that could help increase the adoption of customer owned DERs. A Tariffed-On-Bill ("TOB") financing mechanism is one in which the utility provides the upfront capital for the materials, equipment, and installation of energy improvements that reduce a customer's bill, and then monthly service payments are made that are equal to or lower than the bill savings until the energy improvements are fully paid off. The tariffed based mechanism associates the installed DER measures with the premise, as opposed to a specific customer, until the full cost of the investment is recovered. This allows the measure to be paid off over time even if different customers are moving in and out of the premise. The mechanism makes it much easier for customers and premises to participate in programs targeting locational energy and demand reductions like NWA solutions. It lowers barriers to participation related to home ownership, income, and credit. The first phase of the pilot proposes a budget of \$300,000 to fund more detailed development of the service offering, working closely with stakeholders to flesh out the details of such an offering in Nevada. The first phase would also work to identify and propose a specific field demonstration in distribution constrained areas. Then, if the first phase is successful, the more detailed plans for the service offering along with an

NWA field demonstration would be filed in an Annual DRP Update report requesting approval to move into the next phase.

11. Q. IS NV ENERGY MAKING ANY SPECIFIC REQUESTS OF THE COMMISSION IN THIS DRP?

A. Yes.

12. Q. WHICH SPECIFIC REQUESTS OF THE COMMISSION ARE YOU SUPPORTING IN THIS TESTIMONY?

A. Section 11 of the DRP narrative describes the Companies' requests for the Commission. I support NV Energy's request for Commission approval of Sections 7.A and 7.B of the 2024 DRP narrative as in compliance with Nevada Administrative Code ("NAC") 704.9237(2)(d). I also support NV Energy's request for Commission approval of \$300,000 to support the first phase of its proposed NWA Tariffed-on-Bill Pilot as described in Section 8.A.2.

13. Q. PLEASE DISCUSS WHY THE COMMISSION SHOULD FIND NV ENERGY'S IDENTIFICATION OF ANY INCREMENTAL UTILITY INVESTMENT OR EXPENDITURE NECESSARY TO INTEGRATE COST-EFFECTIVE DERs AS DISCUSSED IN SECTIONS 7.A AND 7.B OF THE DRP AS IN COMPLIANCE WITH NAC 704.9237(2)(d).

A. Sections 7.A and 7.B of the DRP fully describe the status of NV Energy's efforts to cost-effectively integrate, control, and develop grid services for DERs through the DERMS and DOE GSS Grant projects, which require incremental investment on the part of the Companies. My testimony, and specifically Q&As 7, 8, and 9, describe these efforts and related cost updates. The narrative sections provide more

1 detailed schedule and cost updates and ongoing efforts to ensure costs continue to
2 yield a net benefit to customers of the electric utility.

3
4 **14. Q. PLEASE DISCUSS WHY THE COMMISSION SHOULD APPROVE NV**
5 **ENERGY'S PROPOSED NWA TARIFFED-ON-BILL PILOT AS**
6 **DISCUSSED IN SECTION 8.A.2 OF THE DRP.**

7 A. The pilot as proposed offers Nevada stakeholders and the Companies the
8 opportunity to develop and evaluate the performance of a new method of financing
9 to support customer adoption of DERs in distribution constrained areas. The TOB
10 financing mechanism does not involve any third-party loans or property
11 assessments, rather the utility invests the money to cover the remaining upfront
12 project costs of DER projects after all other government, utility, and third-party
13 rebates and incentives have been applied. Cost recovery would consist solely of a
14 monthly tariff charge assigned to the meter at the location where upgrades are
15 installed that is to be paid by the occupant or successor occupant of that location
16 until all of NV Energy's investment costs including authorized returns have been
17 recovered. The projects are purposely designed to allow the bill savings associated
18 with the project to cover the monthly payments while still providing additional bill
19 savings. The method does not create any cross subsidies that would increase any
20 other ratepayer's bill; and it is particularly useful for overcoming the significant
21 barriers to DER adoption faced by low-income customers and small businesses in
22 historically underserved communities. The pilot is conservatively proposed with a
23 first phase that works with stakeholders to identify the jurisdictional specific
24 mechanisms and approaches in Nevada for setting up and delivering a TOB service
25 offering for NV Energy customers. Then, if that phase is successful, a field
26 demonstration would be proposed in an Annual DRP Update report to measure the
27

1 impact of the developed TOB service on lowering upfront investment barriers
2 related to home ownership, income, and credit and on improving the viability of
3 NWAs.

4
5 This opportunity was originally identified by the Nevada Clean Energy Fund and
6 brought to the Program Development working group subcommittee of the DSM
7 Collaborative. These types of efforts require robust stakeholder engagement to
8 ensure appropriate product structuring within the specific local regulatory
9 environment. This type of development effort fills a gap in the overall toolkit used
10 to help ensure resource adequacy, increase electric grid reliability, and provide
11 expanded options for low-income customers and historically underserved
12 communities. The financing option would also support other state and local
13 government initiatives to deploy DER technologies and help maximize the benefits
14 of federal funding allocated to Nevada.

15
16 **SECTION III: DEMAND SIDE MANAGEMENT PLAN NARRATIVE SUPPORT**

17 **15. Q. WHAT IS DSMORE AND WHY DOES NV ENERGY PROPOSE TO**
18 **CHANGE THE DEFAULT COST-EFFECTIVENESS MODEL USED IN**
19 **DSM PLANNING FROM ACE GURU TO DSMORE?**

20 A. Developed and licensed by Integral Analytics (“IA”), the DSMore cost-
21 effectiveness modeling tool is a mature modeling software toolkit that has been
22 used in 30 states to determine the cost-effectiveness of energy efficiency and
23 demand response programs. The Companies have recently acquired DSMore via a
24 request for proposal process to harmonize the valuation of customer programs
25 across the DSM Plan, the DRP, and Transportation Electrification Plan (“TEP”)
26 programs. Benefiting from a robust utility user group, the DSMore modeling toolkit
27

is increasingly being used to model a wide variety of DER customer programs. It can be used to support the determination of locational net benefits associated with DSM programs in the DSM Plan and can be evolved to support the analysis of NWA projects in the DRP. The Companies plan to use DSMore to improve the accuracy of cost-effectiveness testing and to work with stakeholders to prioritize and evaluate potential new benefit streams. NV Energy is working with the software vendor IA to integrate DSMore to IA's distribution planning software LoadSEER to assist in the determination of localized benefits on the distribution system. More details about the functionality of DSMore and the types of benefits that DSMore can model are discussed in the testimony of Dr. Kenneth Skinner.

16. Q. WHY AND WHEN SHOULD THE COMMISSION APPROVE CHANGING THE DEFAULT COST-EFFECTIVENESS MODEL FROM ACE GURU TO DSMORE?

A. The Companies are planning to also use DSMore to evaluate the cost-effectiveness of DRP programs and has used DSMore to evaluate the cost-effectiveness of proposed managed charging programs in the TEP. DSMore will be used as part of a more integrated planning framework and will increase the consistency of and harmonization of the valuations of programs across the DSM Plan, the DRP, and the TEP. DSMore will better support the determination of locational net benefits than Ace Guru, as DSMore evolves and is integrated to LoadSEER. In stand-alone mode, DSMore is shown in this filing to produce comparable results to Ace Guru using the same benefit streams and avoided cost methodologies. Compared to Ace Guru, DSMore has more modeling features and systems integration capabilities and has been shown to be capable of improved valuations for weather sensitive measures and demand flexibility measures. However, the Companies recognize that

DSMore is new to important stakeholders in Nevada. NV Energy will therefore wait to seek approval of the change to DSMore in the next Annual DSM Update or DSM amendment after additional stakeholder review and training on the model via the DSM Collaborative.

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

A. Yes, it does.

EXHIBIT BROWN-DIRECT-1

**Statement of Qualifications
for
MICHAEL O. BROWN
INTEGRATED ENERGY SERVICES DIRECTOR
NV ENERGY
6226 West Sahara Avenue
Las Vegas, Nevada 89146
(702) 402-5421
Michael.Brown@NVEnergy.com**

Summary of Qualifications

Michael has more than 25 years of direct experience in the energy sector with a focus on demand response, energy efficiency, and renewable energy in both deregulated and regulated electricity markets. He has held a variety of positions at consulting and energy service firms, including leadership roles in energy systems analysis; energy efficiency and renewable energy project development and project management; key account management for energy and commodity (gas and electricity) services; product development; and strategy development. Since 2005, Michael has worked at NV Energy. Michael's efforts at NV Energy have included the design and implementation of: one of the largest two-way communicating programmable thermostat programs in the country; an award-winning Home Energy Management program that integrates energy efficiency and demand response; a portfolio of commercial demand response programs utilizing open standard automated communications; and an advanced Demand Response Management System that allows demand side resources to actively participate in utility energy resource portfolio optimization and risk management processes.

Relevant Employment History

Integrated Energy Service Director (October 2022 – Present)

- Provides leadership and strategic direction for portfolio and program design, technology and services pilots, improvements to operational and planning systems, and product development for integrated energy services and programs.
- Serves as business lead for implementation of a Distributed Energy Resource Management system and Department of Energy Grid Services Grant.

NV Energy, Manager (December 2010 – October 2022)

- Managed a team responsible for providing core services in support of the delivery of integrated demand side management programs. Managed services include customer recruitment, customer operations, field services, analytics, engineering, and operations.
- Managed a team responsible for delivering a portfolio of residential, commercial, and agricultural demand response programs, and distributed energy resource integration and optimization.
- Responsibilities included program design and implementation, contract structuring and execution, business process improvement, stakeholder management, analysis of

new products and services, business case development, and integration of demand side resources with smart grid infrastructure.

NV Energy, Sr. Program Manager (May 2006 – December 2010)

- Key program management responsibilities included residential and small commercial direct load control and a federal grant program for consumer information gateway development and integration to enable price-responsive and direct load control.
- Experience also included taking lead role in bidding out and awarding online energy information, billing information, and energy audit software tool for customers.
- Managed Nevada Power Company's portfolio of residential and commercial energy efficiency programs with primary role for air conditioning programs and supporting role for lighting, education, and commercial programs.

Nevada Power Company, Strategist (September 2005 – May 2006)

- Worked in the demand side management planning department to design and develop energy efficiency programs.
- Developed zero energy homes and energy information pilot programs.

Energis Pax, Consultant (January 2004 – September 2005)

- Continued distributed generation strategy development work from business school project for BOC (British Oxygen).
- Evaluated and pursued Clean Development Mechanism opportunities in India.

Luthin Consulting, Contractor (June 2002 – September 2002)

- Short-term contract for energy and commodity management services for health care facilities in New York.

Enron Energy Services (EES), Account Manager (June 2000 to December 2001)

- Managed the operations of energy outsource and large commodity contracts valued in excess of \$300 million.
- Identified additional energy efficiency and demand response opportunities for clients.
- Worked with product structuring group to develop demand response products. Launched a demand response product for customers in New York and Massachusetts and provided leadership and training to fellow account managers in evolving demand response markets in the NYISO and New England ISO.

Enron Energy Services (EES), Project Developer (March 1999 to June 2000)

- Identified and developed energy efficiency projects in industrial and commercial buildings.
- Evaluated energy efficiency technologies and the impact of deregulation on project economics.

ICRC Energy Inc., Project Manager, Energy Services (January 1998 to March 1999)

- Managed a contract with the National Renewable Energy Laboratory (NREL) and the Federal Energy Management Program (FEMP) to provide technical assistance to

- Federal facilities.
- Performed energy efficiency and renewable energy feasibility studies and energy systems design aid.

McNeil Technologies, Inc. and Good Consulting Co., Energy Analyst

(June 1995 to January 1998)

- Supported two U.S. Department of Energy clients: FEMP and The Office of Photovoltaic Technologies.
- Work included supporting the ESPC program, FEMP analytical tools, and the Million Solar Roofs Initiative.
- For Good Consulting, performed energy consumption analysis for EPA laboratories with recommendations for energy efficiency measures.

Education

- **The College of William and Mary**
Bachelor of Science, Double Major, Chemistry and International Relations, May 1994
- **The Cranfield School of Management**
Master of Business Administration, September 2003

Memberships

Peak Load Management Alliance (PLMA) – currently serving as a Co-Chair of the Global Load Management Interest Group. Michael is the immediate past Chair of the Board of Directors, previously served as Vice Chair, an elected member of the Executive Committee and past Chair of the Education Committee. Developed and implemented a three course Demand Response Training Series.

Utility Load Management Exchange (ULME)

Association of Energy Engineers (AEE) - Certified Measurement & Verification Professional; passed Certified Energy Manager exam.

Industry Recognition

Provided leadership and management to the NV Energy teams that were recognized with the following awards:

2014 PLMA Award for Outstanding Commercial Demand Response Program Design

2015 Powergrid International Energy Efficiency/Demand Response Project of the Year Award for the mPowered Home Energy Management Program

2015 AESP Award for Outstanding Achievement in Pricing and Demand Response for the mPowered Home Energy Management Program

AFFIRMATION

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

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

Date: May 31, 2024


MICHAEL O. BROWN

TYLER MEROETH

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05_____

Prepared Direct Testimony of

Tyler Meroth

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

A. My name is Tyler Meroth. I am a Transmission Planning Engineer I in the Transmission System Planning department 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 PROFESSIONAL BACKGROUND AND EXPERIENCE.**

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Nevada, Reno. I began my employment with the Companies as a student engineer in 2022. I have experience in transmission planning, including various compliance tasks and Large Generator Interconnection studies. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Meroth-Direct-1**.

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

3 A. I am responsible for developing electric transmission system models and
4 conducting analyses to assist planning efforts for the Companies' transmission
5 system. I conduct analyses to determine potential risks to system reliability and
6 identify the requirements for mitigation. In addition, I perform studies to determine
7 system upgrades required for the interconnection of new load additions and
8 generator interconnections to the transmission system. I am also responsible for all
9 Non-Wires Alternative ("NWA") analyses for transmission projects associated
10 with the Distributed Resources Plan ("DRP").
11

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

15 A. No, I have not.
16

17 **5. Q. WHAT IS THE PURPOSE OF YOUR PREPARED DIRECT TESTIMONY**
18 **IN THIS CASE?**

19 A. My testimony is in support of Section 3.B of the 2024 DRP narrative, entitled
20 "Distributed Resources Plan Analyses: Transmission Planning."
21

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

23 A. I am sponsoring **Exhibit Meroth-Direct-1**.
24
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7. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF THE DRP NARRATIVE SECTION THAT YOU ARE SUPPORTING IN THIS FILING.

A. Section 3.B – *Distributed Resources Plan Analyses: Transmission Planning* describes the Companies’ activities, processes, and analyses on the transmission system in support of the DRP in the following areas:

1. *Load Forecasting* indicates what forecasts were used in performing the transmission planning analyses in the DRP;
2. *Technical Analysis Methodology* describes the general methodologies used by NV Energy’s Transmission Planning department when conducting NWA analyses;
3. *Grid Needs Assessment – 2024 Capital Plan* (“GNA”) describes how the Companies identified existing and forecasted constraints on their transmission systems for the years 2025 through 2030, the identifying information and parameters of those constraints in terms of the deficiencies involved, the identified traditional wired capital upgrade solutions for addressing those constraints, the Companies’ NWA Suitability/Screening Criteria to determine which of the identified constraints could be suitable for a potential NWA solution, the method and the NWA Screening Analysis Tool that the Companies used to perform the NWA analyses, the results of the NWA analyses, including the sizing of the Distributed Energy Resource (“DER”) technologies (demand response, energy efficiency, conservation voltage reduction, solar photovoltaic, and battery energy storage) used in the potential NWA portfolio, the Present Worth of Revenue Requirements (“PWRR”) analyses that were performed by the Companies comparing the costs of traditional wired capital upgrade solutions against the costs and potential system-level and locational benefits of NWA solutions, and lists

the traditional wired capital upgrade solutions and the NWA solutions that the Companies recommend to address the identified constraints on the transmission system.

8. Q. IS NV ENERGY MAKING ANY SPECIFIC REQUESTS OF THE COMMISSION IN THIS DRP?

A. Yes.

9. Q. WHICH SPECIFIC REQUESTS OF THE COMMISSION ARE YOU SUPPORTING IN THIS TESTIMONY?

A. Section 11 of the DRP narrative describes the Companies' requests for the Commission. Specifically, I support NV Energy's request for Commission approval of Section 3.B of the 2024 DRP narrative as compliant with applicable subsections of Nevada Administrative Code ("NAC") 704.9237, including the following:

1. NV Energy's load and DER forecasting methods as discussed in Section 3.B.1 are in compliance with NAC 704.9237(2)(f); and
2. NV Energy's GNA methods as discussed in Section 3.B.3, including the identification of transmission constraints and projects in Section 3.B.3.a, the NWA analyses in Section 3.B.3.b, the Locational Net Benefits Analysis ("LNBA") in Section 3.B.3.c, and the traditional wired upgrade projects and NWA solutions recommendations in Section 3.B.3.d, are in compliance with NAC 704.9237(2)(a), 704.9237(3)(a), and 704.9237(3)(c).

10. Q. PLEASE DESCRIBE HOW NV ENERGY UTILIZED THE LOAD AND
DER FORECASTS EMPLOYED IN THIS DRP AND WHY THE
COMMISSION SHOULD FIND SUCH ACTIVITIES COMPLIANT.

A. NAC 704.9237(2)(f) states that the DRP must:

Be developed by a utility using a forecast of net distribution system load and distributed resources. The forecast must be for a period of not less than 6 years, beginning with the year after the distributed resources plan is filed. The net distribution system load and distributed resources forecast will include system, substation and feeder level net load projections and energy and demand characteristics for all distributed resource types.

As stated in Section 3.B.1 of the DRP narrative, NV Energy utilized the most recently approved extreme weather, or 1 in 10 year, integrated resource plan (“IRP”) native load forecast, control area load forecast, and as needed, applicable, short-term distribution facility load forecasts at the time analyses were performed, which supported the determination of constraints on the transmission system and the consequent traditional wired upgrade projects (solutions). The load forecasts covered the six-year timeframe following the year of the filing of this DRP.

The above activities meet the requirements of NAC 704.9237(2)(f) with one exception, which is noted in Section 11.B of the DRP narrative. NV Energy is requesting a waiver of the portion of NAC 704.9237(2)(f) that requires that:

The net distribution system load and distributed resource forecast will include system, substation, and feeder level net load projections and energy and demand characteristics for all distributed resource types.

As noted in Section 11.B, NV Energy’s consultant Energy and Environmental Economics, Inc. (“E3”), produced geolocational forecasts for DERs at the census block level and the Companies translated some of that data (EE, DR, and solar

photovoltaic results for 2034) to their distribution feeders and incorporated it into the NWA analyses. As noted in Section 9.A of the DRP narrative, NV Energy will integrate the results from E3's analysis for all DER types into its planning, forecasting, and analyses associated with the DRP as appropriate over the next year ahead of the planned filing of an update to the DRP on or before September 1, 2025, to close this compliance gap. The results from the DRP analyses were not appreciably diminished due to this gap in forecast data.

11. Q. PLEASE BRIEFLY DISCUSS NV ENERGY'S TECHNICAL ANALYSIS METHODOLOGY FOR NWA SOLUTIONS FOR ITS TRANSMISSION SYSTEM.

A. Section 3.B.2 of the DRP narrative generally describes the different types of traditional wired transmission capital upgrade projects and the drivers of these projects from NV Energy's 2024 Capital Plan that underwent NWA analysis. Additionally, this section defines the general methodologies for NWA analysis applied to each type of project and describes how the driver for each project may impact the effectiveness of an NWA solution.

This section provides a detailed explanation of how NV Energy performs its NWA analysis for each project that passes the critical suitability criteria, identifies many of the factors that are not considered in the Companies' NWA Screening Analysis, and provides an in-depth understanding of how NV Energy's Transmission Planning department makes its recommendations for NWA solutions.

1 12. Q. PLEASE DESCRIBE NV ENERGY'S ACTIVITIES REGARDING THE
2 GNA FOR THE COMPANIES' TRANSMISSION SYSTEMS IN THIS DRP
3 AND WHY THE COMMISSION SHOULD FIND SUCH ACTIVITIES
4 COMPLIANT.

5 A. As stated in Sections 3.B.3 of the DRP narrative, NV Energy developed its GNA
6 on its transmission system including NWA analyses, an LNBA, which compares
7 utility infrastructure wired upgrade solutions and DER solutions to forecasted
8 transmission constraints, and recommendations for traditional wired upgrade
9 projects and NWA solutions recommendations. These activities, as described in the
10 DRP narrative, meet the requirements of NAC 704.9237(2)(a), 704.9237(3)(a), and
11 704.9237(3)(c).

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

14 A. Yes.
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EXHIBIT MEROTH-DIRECT-1

**Statement of Qualifications
for
Tyler J. Meroth**

Summary of Qualifications

Two years of electric utility experience all for NV Energy (Nevada Power Company and Sierra Pacific Power Company) based in Reno, Nevada. Experience in transmission planning, interconnection system impact studies, transmission service request system impact studies, and various compliance elements.

Professional Experience

Engineer I, Transmission Planning May 2023 – Current
Nevada Power Company and Sierra Pacific Power Company (d/b/a NV Energy)

Lead in generator interconnection system impact studies. Assists with policy development, compliance work, coordinating advanced studies, and non-wires alternative analysis.

Student Intern, Transmission Planning May 2022 – May 2023
Nevada Power Company and Sierra Pacific Power Company

Assisted planning engineers with various studies, compliance work, data consolidation, and modelling data standardization.

Training, Education, & Memberships

Bachelor of Science Degree in Electrical Engineering; University of Nevada, Reno; 2023

Master of Business Administration; University of Nevada, Reno; 2024

AFFIRMATION

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

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

Date: May 31, 2024



TYLER MEROTH

MISHA PASCAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05____

Prepared Direct Testimony of

Misha Pascal

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

A. My name is Misha Pascal. My current position is Regulatory Analysis Lead for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 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 two Bachelor of Science Degrees, one in Mechanical Engineering and one in Applied Economics and Statistics, with a minor in Business. I have been with the Companies since August 2018 and in my current position since November 2023. Prior to joining the Companies, I worked in equipment management for a large North American construction company. A more detailed description of my background and experience is included in **Exhibit Pascal-Direct-1.**

Pascal-DIRECT

1

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

3 A. My responsibilities include regulatory and technical analysis for a range
4 of filings including new proposals, providing contract support for large
5 customers and filings, supplying departmental support for standby
6 customers, calculating and supporting revenue-based allowances, and
7 supporting the Companies' line extension Rule 9 projects in a general
8 capacity.
9

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

13 A. Yes, I provided written testimony in the Companies' Clean Transition Tariff
14 Advice Letter Applications, Docket Nos. 24-05022 and 24-05023, and first
15 Transportation and Electrification Plan, Docket No. 22-09006, the 2022
16 Sierra General Rate Case ("GRC"), Docket No. 22-06014, and the 2023
17 Nevada Power GRC, Docket No. 23-06014.
18

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

20 A. The purpose of this testimony is to present the Companies' proposal of a Rule
21 9 Allowance ("Allowance") mechanism specific for the facilities required for
22 Electric Vehicle ("EV") charging for commercial customers.
23

24 Currently, allowances are based on project costs traditionally associated with
25 commercial business operations with or without the inclusion of EV charging
26 systems. The new Commercial EV allowance structure presented is a
27

proposal to promote EV adoption and support businesses installing EV charging systems for commercial or at work operations.

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

A. I am sponsoring the following exhibit:

Exhibit Pascal-Direct-1 Statement of Qualifications.

7. Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

A. My testimony explains the foundations of the proposed EV Allowance mechanism to support commercial customers developing EV charging infrastructure.

The Allowance mechanism presented represents a method that promotes EV installations, incentivizes customers within the state to install chargers and promotes EV adoption and charging for commercial fleets and at the workplace.

8. Q. WHAT IS THE PROPOSED MECHANISM FOR THE COMMERCIAL CLASS CUSTOMERS AND HOW WAS IT DETERMINED?

A. For commercial customers, the proposed mechanism modifies the upfront Allowances for EV projects or projects that include EV charging. Currently, when a commercial customer applies for EV charging installations, the allowances are provided in the same manner as for any other commercial project requesting general service. When a customer would like to install a fleet of chargers, the applicable allowance is determined as their peak demand and service size. Below in **Table Pascal-**

Pascal-DIRECT

Direct-1 and **Table Pascal-Direct-2** are the current commercial classes and their appropriate maximum allowance rate:

Table Pascal-Direct 1: Nevada Power 2023 GRC Max Allowance Rates

Rate Class	Units	2023
LRS	kVA	\$466
GS	Meter	\$3,170
LGS1	kVA	\$464
LGS2S	kVA	\$199
LGS2p	kVA	\$205
LGS3S	kVA	\$190
LGS3P	kVA	\$85

Table Pascal-Direct 2: Sierra Pacific Power 2022 GRC Max Allowance Rate

Rate Class	Units	2023
GS-1	Meters	\$6,423
GS-2S	kVA	\$239
GS-2P	kVA	\$100
GS-2-TOUS	kVA	\$114
GS-2-TOUP	kVA	\$100
GS-3S	kVA	\$87
GS-3P	kVA	\$100

When the applicable maximum potential Allowance is determined by the class of customer under **Table Pascal-Direct 1 & 2**, the common practice of applying an Estimated Demand Based Allowance (“EDBA”) percentage is then applied. In Table Pascal-Direct 3 and 4 the percentage is applied against the potential refund amount and represents the upfront allowance to be provided. The customer may receive the remaining allowance balance through refunds. These percentages differ among the territory and class of customer.

Table Pascal-Direct 3: Nevada Power EDBA Percentages
CURRENT NPCE EDBA BUILD-OUT FACTOR

Project Type			EDBA Build-Out Factor %
Parent Project ID			
Commercial			
D1100	1 – 11kVA	(GS)	100%
D1103	12 – 351kVA	(LGS-1)	65%
D1101	352 - 1175kVA	(LGS-2)	40%
D1104	1176kVA and above	(LGS-3)	40%

Table Pascal-Direct 4: Sierra Pacific Power EDBA Percentages

COMMERCIAL - SMALL	GS-1 Secondary (<4kV-<50kV or <10000kWH)	50.00%
COMMERCIAL - SMALL	GS-2 Secondary (<4kV-50kW-499kW)	40.00%
COMMERCIAL - SMALL	GS-2-TOU Secondary (<4kV-500kW-999kW)	40.00%
COMMERCIAL - SMALL	GS-3 Secondary (<4kV->1000kW)	40.00%
COMMERCIAL - MEDIUM	GS-1 Secondary (<4kV-<50kV or <10000kWH)	50.00%
COMMERCIAL - MEDIUM	GS-2 Secondary (<4kV-50kW-499kW)	40.00%
INTERRUPTIBLE IRRIGATION	GS-1 Secondary (<4kV-<50kV or <10000kWH)	60.00%
MULTI FAMILY - SERVICES	GS-1 Secondary (<4kV-<50kV or <10000kWH)	50.00%
MULTI FAMILY - SERVICES	DM-1	40.00%
Residential - Services	D-1	50.00%
COMMERCIAL - SERVICES	GS-1 Secondary (<4kV-<50kV or <10000kWH)	50.00%
COMMERCIAL - SERVICES	GS-2 Secondary (<4kV-50kW-499kW)	40.00%
COMMERCIAL - SERVICES	GS-2-TOU Secondary (<4kV-500kW-999kW)	40.00%
COMMERCIAL - SERVICES	GS-3 Secondary (<4kV->1000kW)	40.00%
OFF SITE FEEDERS	GS-1 Secondary (<4kV-<50kV or <10000kWH)	60.00%
OFF SITE FEEDERS	GS-2 Secondary (<4kV-50kW-499kW)	40.00%
OFF SITE FEEDERS	GS-2-TOU Secondary (<4kV-500kW-999kW)	40.00%
OFF SITE FEEDERS	GS-3 Secondary (<4kV->1000kW)	40.00%

As part of the TEP, the Companies propose to update their process to apply EDBA percentages to 100 percentage for EV projects, thereby allowing the full up-front allowances. This adjustment aims to eliminate one of the barriers to installing EV chargers, which requires significant upfront capital and costs. By removing this barrier for the customer, the proposal promotes the development of EV charging infrastructure in areas where customers have other capital priorities, or limited funding.

This adjustment was determined to be a reasonable measure indirectly within Rule 9 and help local business promote EV charging. This change in procedure incentivizes companies and businesses to install fleet and workplace charging stations by minimizing upfront costs.

9. Q. WHAT ARE THE REQUIREMENTS TO RECIEVE THE EV ALLOWANCES UPFRONT?

A. To receive the allowances upfront, the customer is required to opt onto the applicable electric vehicle charging tariff. These would be the General Service Electric Vehicle Recharge Rider ("OGS-EVRR-TOU"), or the Electric Vehicle Commercial Charging Rider ("EVCCR-TOU"). In addition, the electric vehicle charging infrastructure must be separately metered, and the customer must join the Companies' Managed Charging program. The customer cannot assess drivers an additional fee for using the chargers. These eligibility requirements are discussed in more detail in the testimony of Adam Grant.

10. Q. WHAT IF A CUSTOMER DOES NOT MEET THESE REQUIREMENTS?

A. If a customer does not meet these requirements, the normal Rule 9 process, including the normal application of EDBA percentages (as reflected in the tables above) to decrease an upfront allowance, will continue to apply to the project.

11. Q. HOW DOES THIS ADJUSTMENT IMPACT RULE 9?

A. Rule 9 is not impacted. Section B.3.d states, "These standardized percentages will be applied to the Maximum Allowance to determine the

1 Up-front Allowance to be granted at the time of the execution of the
2 Agreement.”

3
4 With the discretion to apply a new standard percentage, represented as the
5 EDBA percentages, the Rule does not need to be modified in anyway as
6 the percentages follow an internal process that the Commission approved
7 in Docket No. 12-1004 and 12-1005. In this instance, the Companies are
8 simply adjusting the standardized percentages to reflect the eligible TEP
9 applications as 100 percent.

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

13 A. Yes.
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28 Pascal-DIRECT

7

EXHIBIT PASCAL-DIRECT-1

Misha Pascal
Pricing Specialist
RATES & REGULATORY AFFAIRS
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-3571

Mr. Pascal has been an employee of NV Energy since August 2018 and is currently positioned as a Regulatory Analysis Lead within the Rates & Regulatory Affairs department. His current responsibilities are focused upon providing support for large customer projects under development, Rule 9 functions, and work closely with other departments within the utility, such as legal, finance, operations, and engineering, to ensure a cohesive approach to regulatory issues.

Prior to joining the Company, Mr. Pascal had experience as a Maintenance Engineer for a North American Contractor Ledcor. There he provided in depth analysis for processing, safety, and maintenance efficiencies. Responsibilities included analysis of several maintenance programs and present them through initiatives, cost justifications, and rate design.

Employment History

NV Energy
August 2018 to Present

Regulatory Analysis Lead, Regulatory Pricing & Economic Analysis
Pricing Specialist, Regulatory Pricing & Economic Analysis
Senior Pricing Analyst, Regulatory Pricing & Economic Analysis
August 2018 to Present

- Develop Rule 9 initiatives for the Transportation and Electrification Plan.
- Leadership role in developing pricing products.
- Complete transmission and non-transmission facility studies.
- Updated the Sierra Rule 9 allowances.
- Develop customer facilities charges that involve facilities analysis, cost responsibility, bill corrections, and tariff support.
- Analysis for cost estimators and rate developments.
- Provide contract support in several regulatory capacities.
- Provide Rule 9 support for gas and electric projects.

Non-Sierra Employment

Ledcor Group

Dec 2013 to June 2018

Maintenance Engineer

- Established planning programs for preventative maintenance and forecast inventory usage of multimillion dollars in stock parts.
- Conducted impacts of regulatory and safety standards and how the outcomes are affected against production and maintenance.
- Managed service contracts and negotiate rates based on margins required for success.
- Provided in depth equipment analysis during contract creation and negotiation and its impacts.

Education

University of Nevada, Reno

Bachelor of Science in Mechanical Engineering, December 2013.

University of Nevada, Reno

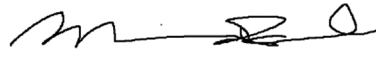
Bachelor of Science in Applied Economics and Statistics May 2001.

AFFIRMATION

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

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

Date: May 31, 2024


MISHA PASCAL

MATHEW JOHNS

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 _____

Prepared Direct Testimony of

Mathew Johns

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

A. My name is Mathew Johns. My current position is Vice President, Environmental Services and Land Management, for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I hold a Bachelor of Science Degree in Civil Engineering and Master of Science Degree in Agricultural Engineering. From 1996 and until I joined the Companies in 2015, I worked on site cleanup and remediation projects nationwide as an environmental engineer, project manager, and program manager for global engineering consulting firms.

1 In 2015, I joined the Companies as Director, Environmental Remediation and
2 Resource Development, with primary responsibility for managing NV Energy's
3 Regulatory Assets and Asset Retirement Obligations ("AROs") for Energy Supply,
4 including decommissioning, demolition, and environmental remediation of the
5 Companies' retired generating facilities. I was also the Companies' representative
6 for generating facility joint partnerships. In 2022, I assumed the role of Vice
7 President, Environmental Services and Land Management.

8
9 My statement of qualifications is attached as **Exhibit Johns-Direct-1**.

10
11 **3. Q. WHAT ARE YOUR DUTIES AND RESPONSIBILITIES IN YOUR**
12 **CURRENT POSITION?**

13 A. I lead a group of directors, managers, engineers, environmental scientists, and land
14 resource professionals who perform or direct environmental analyses, specialty
15 studies, and other tasks necessary for obtaining regulatory approvals and land rights
16 for utility projects. My departments are responsible for all aspects of compliance
17 and permitting pertaining to environmental and land resource matters for the
18 Companies' facilities.

19
20 **4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**
21 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**
22 **("COMMISSION")?**

23 A. Yes. I have submitted pre-filed testimony with the Commission in past Companies'
24 filings for general rate cases and integrated resource plan filings, including most
25 recently Nevada Power's 2023 General Rate Case ("GRC"), Docket No. 23-06005,

and the Fifth Amendment to the Companies' 2021 Joint Integrated Resource Plan,
Docket No. 23-08015.

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

A. The purpose of my testimony is to support the discussion and updates to certain environmental regulatory matters in the Generation Section of the Supply Plan as they relate to the proposed Valmy Simple-Cycle Plant, the Valmy Units 1 and 2 natural gas conversion project, the Tracy Units 4 and 5 ("Tracy 4/5") emissions control project and impacts on fleet operation.¹

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

A. I am sponsoring **Exhibit Johns-Direct-1 - Statement of Qualifications**.

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

A. No.

**8. Q. PLEASE PROVIDE ANY UPDATES RELATED TO THE
ENVIRONMENTAL REGULATIONS SINCE THE FIFTH AMENDMENT
TO THE 2021 JOINT INTEGRATED RESOURCE PLAN, DOCKET NO. 23-
08015.**

A. Certain existing, recently promulgated and proposed environmental regulations were discussed in the Fifth Amendment to the 2021 joint Integrated Resource Plan, Docket No. 23-08015. The discussion below provides updates to these regulations, which are discussed in greater detail in the Generation Narrative.

¹ The Valmy Units 1 and 2 natural gas conversion project and Tracy Units 4 and 5 ("Tracy 4/5") emissions control project were approved by the Commission in Docket No. 23-08015.

Regional Haze Rule

No changes to the Regional Haze Rule (“RHR”) have occurred since the Fifth Amendment to the 2021 Joint Integrated Resource Plan, Docket No. 23-08015.

On March 18, 2024, the Companies submitted a revised four-factor analysis for Valmy Units 1 and 2, based on natural gas operation, and Tracy 4/5 to the Nevada Division of Environmental Protection (“NDEP”). NDEP is currently reviewing the revised four-factor analysis, consulting with the Environmental Protection Agency (“EPA”) and Federal Land Managers (“FLMs”) and preparing regulation, subject to State Environmental Commission approval, to establish legally enforceable requirements for Regional Haze compliance.

On March 29, 2024, EPA entered into a Consent Decree with Sierra Club, National Parks Conservation Association, and Environmental Integrity Project for failure of EPA to act on Regional Haze State Implementation Plan (SIP) revisions for 33 states, including Nevada. The Consent Decree established new timelines for EPA to act on SIPs for each state. For Nevada, EPA has a new “Final Action Date” of December 15, 2025, to approve or deny Nevada’s Regional Haze SIP. NDEP expects to submit a revised Regional Haze SIP to EPA in 2024 upon completion of the regulation, allowing sufficient time for EPA to meet its December 15, 2025, final action date.

Good Neighbor Plan

On May 1, 2024, the EPA published in the Federal Register a Notice of Proposed Settlement Agreement between Nevada Cement Company and EPA relating to the Federal Good Neighbor Plan. The settlement would establish a process and deadlines by which Nevada Cement Company would apply to EPA for a case-by-case emissions limits request (“CBCELCR”) for its Fernley, Nevada, facility in exchange for agreeing

1 to lift a judicial stay in Nevada entered by the U.S. Court of Appeals for the Ninth
2 Circuit.

3 Separately, the United States Supreme Court heard arguments by various parties
4 challenging EPA’s disapproval of state plans as well as the Good Neighbor Plan.

5 It is uncertain how this Nevada Cement Company settlement or other litigation will
6 affect the timing of the Good Neighbor Plan implementation in Nevada.

7
8 **Greenhouse Gas Rule**

9 On April 25, 2024, EPA finalized regulations under the Clean Air Act (“CAA”)
10 Section 111 to address greenhouse gas (“GHG”) emissions (primarily carbon
11 dioxide emissions) from fossil based electric generating units (“EGUs”). The final
12 GHG rule establishes the final best system of emissions reduction (“BSER”) and
13 resulting performance standards for new gas-fired combustion turbines, existing
14 coal units, and oil and gas-fired steam generating units. The final rule did not
15 establish performance standards for existing gas-fired combustion turbines;
16 however, the EPA indicated they may issue a new proposal in the future and will
17 be gathering input through a non-regulatory docket for reducing greenhouse gas
18 emissions from existing gas turbines at power plants.

19
20 **Mercury and Air Toxics Standards**

21 On April 25, 2024, EPA also finalized the National Emission Standards for
22 Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating
23 Units Review of the Residual Risk and Technology rule, commonly known as the
24 Mercury and Air Toxics Standards (“MATS”) to reflect recent developments in
25 control technologies and performance of these plants.

1 In the final rule, the EPA revised the filterable particulate matter (“fPM”) standard
2 for all existing coal based EGUs to 0.010 lb/MMBtu, which is designed to control
3 non-mercury hazardous air pollutants (“HAP”) metals. EPA also finalized the
4 requirement to demonstrate compliance with the revised fPM standard using
5 particulate matter continuous emission monitoring systems (“CEMS”). The revised
6 standards will be effective three years after the effective date of the rule, which is
7 60 days after Federal Register publication.
8

9 **9. Q. DO THESE ENVIRONMENTAL REGULATIONS IMPACT THE**
10 **DECISION TO PURSUE THE VALMY SIMPLE-CYCLE PLANT?**

11 A. The current and proposed regulations do not impact the decision to pursue the
12 Valmy Simple-Cycle Plant comprised of two simple-cycle generating units. Under
13 the GHG rule, these units will be regulated as low-utilization units (capacity factor
14 of 20 percent or less) requiring the use of clean fuel (i.e., natural gas) or
15 intermediate units (capacity factor between 20 and 40 percent), requiring efficient
16 operations and achieving a CO2 emission rate of 1,170 lb. CO2/ MWh. Under the
17 Good Neighbor Plan, the units would be integrated into the program and establish
18 nitrogen oxides (“NOx”) emission budgets through new unit set aside procedures.
19 The units may also be considered under Regional Haze during future decadal
20 planning periods; however, no additional requirements would be expected as they
21 will be constructed with selective catalytic reduction (SCR) for NOx emission
22 control. MATS standards are not applicable to these units.
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10. Q. HOW DO UPDATES TO THESE ENVIRONMENTAL REGULATIONS
SINCE DOCKET NO. 23-08015 IMPACT THE VALMY UNITS 1 AND 2
NATURAL GAS CONVERSION AND NO_x EMISSION CONTROLS
PROJECT?

A. Based on the timing resulting from the EPA Consent Decree establishing a new
approved deadline of December 15, 2025, for Nevada's Regional Haze SIP and
Nevada Cement Company Settlement and uncertainty related to the Good Neighbor
Plan implementation in Nevada, the Companies expect to implement the Valmy
Units 1 and 2 natural gas conversion and installation of NO_x controls in two phases.

The Companies are preparing a permit application to proceed with the natural gas
conversion on the currently planned timelines to allow for coal-fired generation to
cease by the end of 2025. The Companies expect to file a separate permit
application in 2025 with NDEP to incorporate selected NO_x controls following re-
submittal of the Regional Haze SIP. The will also allow time to access Good
Neighbor Plan outcomes during 2024.

The timeline to install NO_x controls under Regional Haze will be established by
the NDEP. Timelines under the Good Neighbor Plan, if it becomes effective in
Nevada, are uncertain. Under the RHR, it is expected that NO_x controls will need
to be installed within 36 months after EPA approval of Nevada's Regional Haze
SIP.

The Valmy natural gas conversion is expected to meet the standards for the existing
gas-fired steam units under the final GHG rule. The MATS rule does not affect

Valmy Units 1 and 2 as the conversion to natural gas operation that will be complete ahead of the timeline in which the revised standards take effect.

11. Q. DO THE UPDATES TO THESE ENVIRONMENTAL REGULATIONS SINCE DOCKET NO. 23-08015 IMPACT THE TRACY 4/5 PROJECT?

A. Based on the timing resulting from the EPA Consent Decree establishing a new approved deadline of December 15, 2025, for Nevada’s Regional Haze SIP, the Companies will file a separate permit application with NDEP in 2025 to incorporate selected NOx controls following NDEP’s submittal of the revised Regional Haze SIP.

Under the RHR, it is expected that NOx controls will need to be installed within 36 months after EPA approval of Nevada’s Regional Haze SIP. Outcomes of the Good Neighbor Plan do not affect the Tracy 4/5 project.

12. Q. HOW DO THESE REGULATIONS IMPACT THE REMAINDER OF NV ENERGY’S FLEET?

A. Prior assessment under the RHR did not identify additional NV Energy units, besides the Valmy and Tracy units, for which emission controls were considered to support visibility protection for Federal Class 1 areas, such as Jarbidge Wilderness Area.

The Good Neighbor Plan, if it becomes effective, would include NV Energy’s fleet, except for Brunswick, in the state NOx allowance program for operation during the ozone season. As discussed under the Good Neighbor Plan, NOx allowances for Valmy Units 1 and 2 would eventually be based on a NOx emission rate

commensurate with SCRs. The remaining units are either already controlled or have historic NOx emissions below applicable Good Neighbor Plan thresholds that EPA would base NOx allowances on SCR installation.

Under the final GHG rule, Fort Churchill Units 1 and 2, and Tracy Unit 3 will also be regulated under the existing gas-fired steam unit requiring routine methods of operation and maintaining CO2 emission rates of between 1,400 to 1,600 lb. CO2/MWH based on unit capacity factors. Fort Churchill Units 1 and 2 and Tracy 3 currently operate within or below these CO2 emission rates. The Silverhawk Peaking Plant will be considered new units under the GHG rule as construction started after May 23, 2023. These units would fall under the low-utilization category (20 percent capacity factor or less) which only requires use of clean fuels (i.e., natural gas). The remaining existing NV Energy units are not impacted by the April 25 final rule but may be part of future EPA proposals.

The proposed updates to MATS are specific to coal- and oil-fired units and do not impact the remainder of NV Energy's fleet.

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

A. Yes.

EXHIBIT JOHNS-DIRECT-1

MATHEW J. JOHNS
VICE PRESIDENT, ENVIRONMENTAL SERVICES AND LAND MANAGEMENT
NV Energy, Inc.
6226 West Sahara Avenue
Las Vegas, NV 89146
(702) 402-5477

Mr. Johns joined NV Energy in August 2015. He has over 25 years of experience in environmental remediation, project, and program management. Prior to joining NV Energy, Mr. Johns worked as an environmental consultant for industrial companies primarily in the power, manufacturing, mining, oil and gas sectors.

EMPLOYMENT HISTORY

NV Energy, Inc.
8/2015 to 2/2022

Director, Environmental Remediation and Resource Development

Primary responsibility for managing Regulatory Assets and Asset Retirement Obligations (“AROs”) for Energy Supply. These obligations include decommissioning, demolition, and environmental remediation of the company’s generating facilities.

3/2022 to Present

Vice President, Environmental Services and Land Management

Primary responsibility for leading the teams responsible for all aspects of compliance and permitting pertaining to environmental and land resource matters for Nevada Power and Sierra facilities.

CH2M HILL
6/2000 to 7/2015

Project and Program Management Assignments:

- Owner's Engineer and Construction Management (OECM), power client (2008 to 2014). Responsible for the planning, permitting, engineering and construction oversight services for wastewater and solid waste improvement and related closure projects at a coal-fired power plant.
- Program Design Manager, manufacturing client program, U.S. Nationwide (2011 to 2014). Responsibilities included establishing design teams, identifying delivery approaches, and ensuring best practices to deliver design-construction projects in an efficient manner for environmental remediation projects across the United States.
- Program Management for Greenfield Refined Products Pipeline (2007-2008). Assistant manager for preliminary engineering, cost estimating and permitting phase services for a grass-roots 400-mile refined products pipeline in the southwestern US.

Facilities Operations and Management Assignments:

- Interim Measures and Groundwater Response Action, Power Client, CA (2004-2005). Managed an immediate groundwater response action to establish hydraulic control of chromium-contaminated groundwater near a critical drinking water body in the

southwestern United States. Activities included construction of onsite batch treatment and temporary storage facilities, transportation, and offsite disposal.

- Facility Operations and Compliance Groundwater Extraction and Treatment System, Power Client, CA (2005-2006). Managed for the start-up and operation of a groundwater extraction and treatment system for chromium-contaminated water. The water was treated to rigorous permit limits allowing for onsite disposal into injection wells. Onsite staff included a site operations manager, up to eight full-time operators providing 24-hour/7-day per week operations, engineering staff focused on facility optimization, and environmental compliance specialists.

Other Project Management and Technical Experience

- Mine site closure and post-closure monitoring, Colorado (2006 to 2015)
- Groundwater permeable reactive barrier design, Michigan (2005).
- Municipal landfill closure, Federal facility, Wyoming (2000 to 2004).
- Groundwater investigations, Federal facility, Wyoming (2000 to 2004).
- Groundwater permeable reactive barrier pilot study, Texas (2002 to 2003).
- Groundwater treatment systems design, Federal facilities, Florida (2000 to 2005).

ERM-SOUTHWEST 6/1996 – 6/2000

Project Engineering Assignments

- Coal ash landfill closure design, Texas
- Calcium carbide waste disposal site closure design, Michigan.
- Groundwater slurry wall design, Texas
- Groundwater recovery trench design, Texas
- Hazardous and non-hazardous landfill closure design, Texas
- Corrective action management unit application and design Basis, Texas

EDUCATION

Master of Science in Agricultural Engineering, Texas A&M University, 1996

Bachelor of Science in Civil Engineering, University of Colorado, 1994

PROFESSIONAL REGISTRATIONS

Registered Professional Engineer – Civil Engineering - Arizona

Registered Professional Engineer – Civil Engineering - Nevada

Registered Professional Engineer – Civil Engineering - Texas

AFFIRMATION

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

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

Date: May 31, 2024


MATHEW JOHNS

JOHN LESCENSKI

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

2024 Joint Integrated Resource Plan (2025-2044)

Docket No. 24- 05_____

Prepared Direct Testimony of

John Lescenski

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

A. My name is John Lescenski. My current position is Manager, Generation Engineering and Technical Services, for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the “Companies”). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I have worked in NV Energy’s Energy Supply (Generation) department for the past 35 years in various engineering and management roles. My statement of qualifications is attached as **Exhibit Lescenski-Direct-1**.

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

3 A. As Manager, Generation Engineering and Technical Services, I am
4 responsible for generation fleet-wide asset strategy development, regulatory
5 planning and analysis, technical support for new solar resource contracts and
6 technical support to the Companies' generation fleet.

7
8 **4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**
9 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**
10 **(“COMMISSION”)?**

11 A. Yes. I provided written testimony in past Companies' filings for deferred
12 energy, integrated resource planning and general rate cases, including most
13 recently in Docket Nos. 23-08015, 23-06007 and 24-02026

14
15 **5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

16 A. The purpose of my testimony is to support the Supply Plan for the
17 Companies' fossil generation and the engineering issues related to the
18 proposed Valmy Simple Cycle Plant included in the Preferred Plan.

19
20 **6. Q. WHAT EXHIBITS AND APPENDICES ARE YOU SPONSORING?**

21 A. I am sponsoring the following Exhibit and Technical Appendices:
22 **Exhibit Lescenski-Direct-1 – Statement of Qualifications**

Technical Appendix GEN-1 – Generating Unit Characteristics Table
(CONFIDENTIAL)

Technical Appendix GEN-2 – Emissions Rates - Generation

Technical Appendix GEN-3 – New Generation Brownfield Study
(CONFIDENTIAL)

Technical Appendix ECON-10 – Firm Dispatchable Resources

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

A. Yes. Technical Appendix GEN-1 includes the Generating Unit Characteristics Table that provides characteristics used in the dispatch of the Companies' generating units. Technical Appendix GEN-3 includes cost projection details for potential future generating units. These confidential technical appendices contain commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information discloses the Companies' views and expectations of the relevant markets 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

1 and impair the Companies' ability to achieve the most favorable pricing and
2 terms and conditions from suppliers on behalf of their customers.

3
4 Additionally, the confidential information in the Generation section of the
5 Supply Plan Narrative is described below:

- 6 • Table GEN-3 provides specific cost expectations for the Silverhawk
7 project components that are not competed and providing this
8 information publicly would disadvantage the Companies in the final
9 contract negotiations and closure and result in higher project costs.
- 10 • Table GEN-4 is based on indicative bids for the Valmy gas repower
11 project that are currently being negotiated and public release of this
12 information would disadvantage the Companies in ongoing contract
13 negotiations and result in higher project costs.
- 14 • Table GEN-6 contains cost expectations for project components for the
15 Valmy Simple-Cycle Plant that are currently being negotiated or that
16 will be negotiated in the future. Public release of this information
17 would disadvantage the Companies in contract negotiations and result
18 in higher project costs.
- 19 • Table GEN-7 contains cost expectations for the Valmy Simple-Cycle
20 Plant project components that are currently being negotiated or that
21 will be negotiated in the future. Public release of this information
22 would disadvantage the Companies in contract negotiations and result
23 in higher project costs.

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

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

4
5 **9. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF**
6 **THE COMMISSION’S REGULATORY OPERATIONS STAFF**
7 **(“STAFF”) OR THE NEVADA ATTORNEY GENERAL’S BUREAU**
8 **OF CONSUMER PROTECTION (“BCP”) TO FULLY INVESTIGATE**
9 **THE INFORMATION SET FORTH IN THIS FILING?**

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

13
14 **10. Q. HOW IS YOUR TESTIMONY ORGANIZED?**

15 A. In Section II, I describe the approved generation related projects that are still
16 under development or construction. In Section III, I describe the Valmy
17 Simple-Cycle Plant.

18
19 **SECTION II: PREVIOUSLY APPROVED PROJECT STATUS**

20 **11. Q. PLEASE DESCRIBE THE PREVIOUSLY APPROVED PROJECTS**
21 **YOU ARE SUPPORTING.**

1 A. I am supporting the following projects that were approved by the Commission
2 in previous Integrated Resource Plans (“IRP”) or IRP Amendments and are
3 described in the Supply Plan, Generation, section of the narrative:

- 4 • Turbine Upgrades and Wet Compression
- 5 • Lenzie Chilled Water Storage
- 6 • Silverhawk Peaking Plant
- 7 • Valmy Natural Gas Conversion
- 8 • Tracy 4 and 5 Selective Catalytic Reduction Project

9
10 **SECTION III: VALMY SIMPLE-CYCLE PLANT**

11 **12. Q. PLEASE DESCRIBE THE VALMY-SIMPLE CYCLE PLANT.**

12 A. The Valmy Simple-Cycle Plant is a 400 MW (nominal rating) simple-cycle
13 generating plant to be located at the Valmy Generating Station. The estimated
14 cost of the project is approximately \$573.3 million (without AFUDC).

15
16 Like the Silverhawk Peaking Plant approved in Docket No. 23-11032, the
17 proposed simple-cycle generating units for the Valmy Simple-Cycle Plant are
18 highly efficient, state-of-the-art, combustion turbines. They would be
19 installed with equipment to reduce emissions. A combination of dry low-NOx
20 combustion systems, selective catalytic reduction and carbon monoxide
21 catalyst will be incorporated into the design. Also, like the Silverhawk
22 Peaking Plant, these units would be capable of operating a hydrogen mixture
23 when hydrogen fuel sources are available.

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**13. Q. HOW WILL THE NATURAL GAS BE SUPPLIED FOR THE
PROPOSED VALMY SIMPLE-CYCLE PLANT?**

A. The Pinyon natural gas lateral is being constructed to support the approved Valmy Units 1 and 2 natural gas conversion. This lateral has sufficient capacity to supply the natural gas to operate the proposed Valmy Simple-Cycle Plant.

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

A. Yes.

Lescenski-DIRECT

7

EXHIBIT LESCENSKI-DIRECT-1

JOHN W. LESCENSKI
MANAGER, PLANT ENGINEERING AND TECHNICAL SERVICES

Currently Manager, Plant Engineering and Technical Services at NV Energy, responsibilities include generation fleet-wide asset strategy development, regulatory planning and analysis, technical support for new solar resource contracts, working to ensure the existing and future generation fleet of power plants meets the energy supply requirements of our customers.

Professional Experience

Joining Nevada Power (now NV Energy) in 1989 as an Engineer in Generation Engineering and Construction at the Reid Gardner Power Plant, progressing to Manager for strategy planning for integrating business planning with power plant operations, in conjunction as primary witness for Generation issues in regulatory filings of the Integrated Resource Planning, Depreciation Cases, and General Rate Cases. Leading development of 10-year Business Plans for all generating plants in the fleet, leading plant repowering/retirement analysis and providing input to Resource Planning for alternative analysis. Responsible for strategic assessments of NV Energy's generation fleet through plant condition assessments and long term life span analysis.

- Primary point of contact for regulatory filings for generation issues: testimony, narrative, data request, witness, witness support
- Technical Support for Renewable PPA contract RFPs and renewable project development
- Technical Support for Solar PPA contract compliance with Energy Contract Management
- Successfully completed the \$54 million Nellis Solar PV2 project, installing a 15MW photovoltaic station on a closed landfill on the Nellis Air Force Base. Responsible as project manager from contracting and construction management through startup
- Successfully completed the \$16 million King's Beach Power Plant replacement, responsible for the project from inception through start-up
- Lead early efforts in the development of the Ely Energy Center project
- Lead the study of the Valmy expansion alternatives
- Spearheaded the resource planning efforts for the retirement and decommissioning of the Clark Units 1-3 and their replacement with the new 600 MW Clark Peaking Plant.
- Coordinated with Environmental Services on the air permit application and permitting for the contemporaneous change for the Clark Peaker Project
- Coordinated the Reid Gardner emissions alternative analysis and resource planning approval and supported the regulatory filings for emissions upgrades and the eventual retirement
- Developed Life-Span Analysis Process (LSAP) to guide the decision making for determining the remaining economic useful life of a generating unit and reinvestment decisions to continue operations. This Process is now relied upon by the Public Service Commission of Nevada.
- Project Engineer for the Harry Allen Unit 4 simple cycle 7EA combustion turbine expansion project, supporting resource plan application/approval through turbine purchase and EPC bidding and contracting
- Lead technical analyst for the generation business services department, providing services as lead Owner/user inspector and subject matter expert supporting the Clark and Reid Gardner Plant Engineering Staff.

Education

Master of Arts in Economics – University of Nevada, Las Vegas • 2019

Professional Paper: Econometric Analysis of the Effect of Deregulation on Retail Energy Prices

Graduate Certificate in Post-Secondary Teaching – University of Nevada, Las Vegas • 2019

Graduate Certification in Renewable Energy – University of Nevada, Reno • 2013

Master of Business Administration – University of Nevada, Las Vegas • 1996

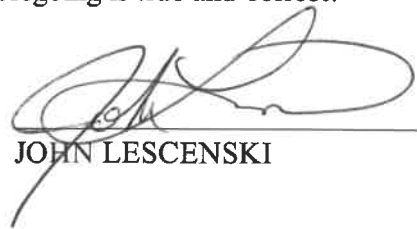
Bachelor of Science in Mechanical Engineering – University of Southern California • 1989

AFFIRMATION

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

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

Date: May 31, 2024



JOHN LESCENSKI

CHARLES A POTTEY

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 ____

Prepared Direct Testimony of

Charles A. Pottey

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

A. My name is Charles Pottey. I am the Director of Transmission 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 BACKGROUND AND EXPERIENCE IN THE
UTILITY INDUSTRY.**

A. I have a Bachelor of Science degree in Electric Power Engineering and a Master of Engineering degree in Electric Power Engineering, both from Rensselaer Polytechnic Institute. I am a registered Professional Engineer. I have more than 45 years of experience in the electric utility industry mostly with the Companies. I have experience in transmission planning, resource planning, distribution planning, rates and regulatory affairs, transmission business services and electric grid operations. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Pottey-Direct-1**.

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

3 A. I am responsible for all transmission planning associated with integrated resource
4 plans (“IRP”), compliance, generator interconnections and transmission service
5 requests, including load addition functions for the Companies.

6
7 **4. Q. HAVE YOU PREVIOUSLY SUBMITTED PRE-FILED TESTIMONY**
8 **WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA**
9 **(“COMMISSION”)?**

10 A. Yes, I have testified in many IRP, IRP amendments and rate case proceedings,
11 including most recently in Docket No. 23-08015.

12
13 **5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

14 A. I sponsor the Transmission Plan section of the Supply Plan narrative discussing the
15 Companies’ transmission systems and associated projects, except for the transmission
16 additions required for large customer load additions. The transmission additions
17 required for large customer load additions are mainly sponsored by Mr. Layne
18 Maxfield, but I also touch upon three of the projects discussed by Mr. Maxfield. I
19 explain why the Greenlink projects are needed and discuss possible alternatives to the
20 project. I also support the jobs and economic benefits for new transmission projects
21 presented in the Transmission Plan. Additionally, I support the Companies’ requests
22 to construct the required transmission system network upgrades for the Preferred Plan
23 or the Alternate Plan including:

- 24 1. Tolson 336 MVA 230/138 kV transformer.
25 2. Reid Gardner-Harry Allen 230 kV Transmission Line #3.
26 3. Lantern-Comstock Meadows 345 kV Transmission Line.
27

4. Machacek Substation 230 kV Breaker Additions.
5. Ft. Churchill-Comstock Meadows 345 kV Transmission Line #2.
6. Ft. Churchill 525/345 kV Transformer #3 and #4.
7. Permitting for the Ft. Churchill-Veterans 525 kV Transmission Line.
8. Valmy 345 kV Terminal Position for 411 MW Combustion Turbines.
9. Harry Allen 230 kV Terminal Position for 200 MW PV Solar/Battery.
10. Ft. Churchill 345 kV Terminal Position for 700 MW PV Solar/Battery.

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

A. I am sponsoring the following Exhibits:

- **Exhibit Pottey-Direct-1** – Statement of Qualifications.

I am sponsoring the following Technical Appendices:

- **Technical Appendix Trans-1** – Greenlink Nevada Study.

7. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I explain why the Greenlink transmission projects remain the best alternative to provide the necessary increase in transmission capacity to meet the Companies' transmission obligations. I then discuss the Companies' requests to construct the required transmission system network upgrades required to interconnect requested resource additions and to meet system reliability requirements.

Greenlink transmission projects:

8. Q. WHY ARE THE GREENLINK TRANSMISSION PROJECTS NEEDED?

A. Additional system import, export and transfer capacity between northern and southern Nevada are needed to meet Nevada's renewable energy goals. Transmission capacity

is also needed to access renewable energy zones that will be necessary to meet the state's renewable energy goals. In addition to achieving the state's renewable goals, under the Open Access Transmission Tariff ("OATT"), NV Energy has a federal obligation to plan for the electric service to all existing and future network customers. Network customers, which take Network Integration Transmission Service ("NITS") under the OATT, are treated with the same priority as NV Energy's native load and pay for transmission service based on their proportionate share of the total system load. NV Energy's native load is the largest network customer. The import limit in northern Nevada is 1,275 MW and is fully reserved based on 150 MW of Transmission Reliability Margin, 600 MW of ON Line allocation for native load and 525 MW of third-party firm reservations. The 525 MW of third-party reservations is forecasted to increase by an additional 681 MW within 10 years. Investment in transmission infrastructure is the only possible way to increase the import into northern Nevada to meet this increasing transmission load growth. The addition of Greenlink West will increase the northern Nevada system limit to 2,000 MW. However, all of that additional system import capacity except for 44 MW has been allocated to existing Network customers based on prior queued transmission service requests.

9. Q. IN ADDITION TO THE OATT OBLIGATIONS, ARE THERE RELIABILITY REQUIREMENTS RELATED TO THE COMPANIES' NEED TO EXPAND THEIR SYSTEM?

A. Yes. The Federal Energy Regulatory Commission (FERC) expanded the reliability-related elements of the federal regulatory structure beyond just the OATT when it implemented the reliability directives contained in the Energy Policy Act of 2005. FERC did this by instituting mandatory reliability standards that all users of the bulk electric system ("BES") must follow, including transmission providers.

10. Q. WHO OVERSEES DEVELOPMENT OF AND COMPLIANCE WITH
TRANSMISSION PROVIDER RELIABILITY STANDARDS?

A. FERC delegated authority to the North American Electric Reliability Corporation (NERC) to develop reliability standards to ensure the safe and reliable operation of the BES in the United States in a variety of operating conditions. On April 1, 2005, NERC established a set of transmission operations reliability standards.

11. Q. IS COMPLIANCE WITH THE RELIABILITY STANDARDS OPTIONAL?

A. No. The reliability standards are a federal requirement, subject to oversight and enforcement by the Western Electricity Coordinating Council (WECC), NERC, and FERC. NV Energy is subject to compliance audits every three years and may be required to prove compliance during other NERC or WECC reliability initiatives or investigations. Failure to comply with the reliability standards could expose the Companies to penalties of up to \$1 million per day, per violation.

12. Q. IS THERE A SET OF RELIABILITY STANDARDS MOST RELEVANT TO
GREENLINK?

A. Yes. A subset of the transmission reliability standards called the transmission planning standards (“TPL Standards”) are most relevant to the Greenlink lines. The purpose of the TPL Standards is to “establish transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.”¹ The TPL Standards, along with regional planning criteria (i.e., regional planning criteria established by WECC and utility-specific planning criteria),

¹ See NERC Standard TPL-001-5, Transmission System Planning Performance Requirements, available at <http://www.nerc.com/files/tpl-001-5.pdf>.

define the minimum transmission system requirements to safely and reliably serve customers.

13. Q. HOW DO NERC’S AND WECC’S STANDARDS AND CRITERIA INFLUENCE THE NEED FOR THE GREENLINK PROJECTS?

A. The mandatory standards, particularly NERC’s TPL-001-5 standard, require the Company to have a forward-looking transmission plan to reliably serve current and anticipated customer demands under all expected operating conditions, including normal system operations (all system elements in service) and during system contingencies (where multiple elements of the transmission system are out of service), both planned and otherwise.

The Companies perform annual reliability assessments to determine whether the transmission system complies with minimum mandatory system performance standards, which require that, during loss of any single transmission system element (“N-1 single contingencies”), firm service is maintained, no system overloads exist, and there is no loss of customer demand. The Companies must also plan how they will respond to the second outage (this type of scenario is referred to as an N-1-1 condition).

Greenlink has been included in the Companies’ annual TPL-001-5 assessment as part of its short- and long-term plans to dependably meet NERC and WECC reliability requirements. The Greenlink segments are particularly effective in increasing system reliability under the various multiple contingency categories of the TPL-001-5 standard.

14. Q. ABSENT CONSTRUCTION OF GREENLINK WEST AND GREENLINK NORTH, WOULD NV ENERGY STILL NEED TO DEMONSTRATE RELIABLE OPERATIONS UNDER THE VARIOUS CONTINGENCY CATEGORIES OF THE TPL-001-5 STANDARD?

A. Yes. The only way NV Energy could stop pursuing construction of any transmission facilities in Nevada and maintain compliance with the TPL-001-5 standard is if the transmission system experienced *no* changes in loads or resources. As I discussed above, however, NV Energy has received, processed, and executed contracts associated with thousands of MWs of requests for OATT service that cannot be reliably provided absent construction of the Greenlink lines or their functional equivalent. Stated another way, the system impact studies for those OATT service requests identified that addition of any of the incremental generation projects requesting service would result in system deficiencies during N-1 or N-1-1 conditions in violation of TPL-001-5 if allowed to interconnect absent the Greenlink projects.

15. Q. ARE THERE OTHER SYSTEM RELIABILITY CONCERNS IF THE GREENLINK TRANSMISSION PROJECTS ARE NOT AVAILABLE?

A. Yes. The base load forecast for northern Nevada forecasts that the peak load will increase by 1,615 MW over the next 10 years. Sierra is planning resource additions to serve this level of load growth. However, there are executed agreements for 4,000 MW of additional load and an additional 6,000 MW of proposed load additions in the study phase in northern Nevada over the next 10 years. The Companies expect that not all of these loads will actually materialize. Historically, the Companies have seen that the actual load that materializes is significantly less than the load growth forecast by the customers. Other utilities have confirmed that they are experiencing similar trends. In order not to construct generation resources and transmission facilities that are not

needed if the full customer load forecast does not materialize, NV Energy has discounted the customer load forecast to account for actual loads being less than the customers forecast. However, if actual load growth is higher than NV Energy's forecast, the Greenlink projects provide additional system import capacity that can be used to serve the unexpected load growth. Without the additional system import capacity, it likely will not be possible to serve additional load growth beyond the load forecast.

16. Q. HOW DOES THE WEATHER POTENTIALLY IMPACT SYSTEM RELIABILITY IF THE GREENLINK TRANSMISSION PROJECTS ARE NOT AVAILABLE?

A. Much of the additional generation being proposed to serve forecast load growth in northern Nevada is PV solar resources. During winter storms, there can be extended periods of cloud cover and snow. Energy output from these facilities could be curtailed for a number of days due to cloud cover or snow covering the PV panels. The Greenlink projects provide additional system import capacity that can be used to serve the load with resources from other regions that may not be impacted by the storm. Without the additional system import capacity, it may not be possible to serve all of the load in northern Nevada during periods when PV generation is curtailed due to cloud cover and snow for extended periods.

17. Q. HAS NV ENERGY EVALUATED TRANSMISSION ALTERNATIVES TO THE GREENLINK TRANSMISSION PROJECT?

A. Yes. In Docket No. 20-07023, the Fourth Amendment to the 2018 IRP, a number of alternatives were evaluated to meet the need to expand the transmission system. Due to the forecast in cost increases required to construct the Greenlink project,

NV Energy has reevaluated whether there is a lower cost transmission alternative that would provide the benefits provided by the Greenlink project at a lower cost.

18. Q. WHAT ALTERNATIVES TO THE GREENLINK TRANSMISSION PROJECT WERE EVALUATED?

A. In Docker No. 20-07023, the Companies evaluated nine transmission alternatives to provide additional transmission capacity. For this analysis, the Companies have reviewed these alternatives to determine whether any of the alternatives could provide the needed transmission capacity at a lower cost. These alternatives included:

1. Falcon to Midpoint 345 kV line
2. Robinson to Valmy 345 kV line
3. Alturas 345 kV Reinforcement
4. Ft. Churchill to Robinson 525 kV line (Greenlink North)
5. Ft. Churchill to Northwest to Harry Allen 525 kV line (Greenlink West)
6. Ft. Churchill to Captain Jack 525 kV line
7. Robinson to Midpoint 525 kV (SWIP-N)
8. Robinson to Clover 525 kV (Cross-Tie)
9. Robinson to Harry Allen #2 (ON Line #2)

19. Q. HOW DO THESE ALTERNATIVES COMPARE TO THE GREENLINK TRANSMISSION PROJECT?

A. The Companies evaluated each of the above transmission alternatives to determine whether any of the alternatives could provide the required transmission system improvements at a lower cost. A scoring system was developed for ranking the

transmission options based on several factors, the result of this scoring is shown below.

Transmission Options Analysis Matrix												
#	Project	Increases Import <100=0, 100-500=1, 500-1000=2	Renewable Integration in Nevada	Nevada Joint Dispatch	Relieves Congested Path	Accesses Existing Available Capacity	Facilitates Fossil Fuel Retirement	No Third Party Transmission Rate	Supports Major Load Pockets, Reno & Tracy	Access to Renewable Energy Zones	Follows existing Transmission	Total Score
1	Falcon - Midpoint 345kV	1	0	0	0	0	1	0	0	0	1	3
2	Robinson - Valmy 345kV	1	0	1	0	1	1	1	0	0	1	6
3	Alturas 345kV Capacity Upgrade	1	0	0	0	0	0	0	0	0	0	1
4	Fort Churchill - Robinson 525kV	2	1	1	0	1	1	1	1	0	1	9
5	Fort Churchill - Northwest - Harry Allen 525kV	2	1	1	1	1	1	1	1	1	0	10
6	Fort Churchill - Captain Jack 525kV	2	1	0	0	0	1	0	1	0	0	5
7	Robinson - Midpoint 525kV (SWIP North)	0	0	0	0	0	0	0	0	0	0	0
8	Robinson - Clover 525kV (Cross-Tie)	0	0	0	0	0	0	0	0	0	0	0
9	Harry Allen - Robinson 525kV #2 (ON Line #2)	0	0	0	1	1	0	1	0	1	1	5

As shown in the Transmission Options Analysis Matrix, the Greenlink project remains the best alternative to provide the necessary transmission capacity. No other project or combination of projects provide the required system import and export capacity, total transfer capacity (TTC) between northern and southern Nevada, ability to interconnect planned renewable energy projects and the ability to meet transmission service obligations for NITS customers.

20. Q. WOULD ANY OF THE ALTERNATIVE TRANSMISSION PROJECTS BE LESS COSTLY THAN THE GREENLINK TRANSMISSION PROJECT?

A. Yes. Some of the nine transmission alternatives are lower voltage and shorter. They would, therefore, cost less to construct. However, as shown in the analysis matrix, they do not provide the required transmission capacity to meet the Companies'

transmission service obligation. Although the Greenlink project has experienced cost escalation, there is no reason to believe that the alternative transmission projects would not also experience similar cost escalation. As John Tsoukalis's Prepared Direct Testimony demonstrates, Greenlink costs increases are less than those experienced by the transmission infrastructure industry generally.²

21. Q. FOR THE ILLUSTRATIVE GENERATION EXPANSION PLAN WITHOUT GREENLINK PROVIDED IN THE ECONOMIC ANALYSIS SECTION OF THE RESOURCE PLAN, WHAT RESOURCE ADDITIONS ARE REQUIRED?

A. Without Greenlink, for the illustrative generation expansion plan, it was necessary to add local generation resources to serve the forecast load growth. These resources included additional renewable resources located at Amargosa, Esmeralda and Lander substations.

22. Q. WHAT TRANSMISSION ADDITIONS WOULD BE REQUIRED FOR THE ILLUSTRATIVE GENERATION EXPANSION PLAN?

A. Generator lead lines are required to connect the renewable resources located at Amargosa, Esmeralda and Lander substations to the load. This would require constructing the Amargosa-Northwest segment of Greenlink to connect the Amargosa resource to the Nevada Power system. To connect the Esmeralda and Lander resources to the Sierra Pacific system the Esmeraldas-Ft. Churchill and Lander-Ft. Churchill segments of the Greenlink project are needed. To deliver the resources from Ft. Churchill to the northern Nevada load center, the Common Ties

² John Tsoukalis's Prepared Direct Testimony, Analysis of Greenlink Costs, at 26-30.

are also required. The estimated cost of these transmission line segments is \$3,087 million.

23. Q. WOULD THE ILLUSTRATIVE GENERATION EXPANSION PLAN WITHOUT GREENLINK MEET THE SYSTEM TRANSMISSION REQUIREMENTS?

A. No. This plan does not provide any increase in the system import limit or an increase in the transfer capacity between northern and southern Nevada. Without additional system import capacity, the FERC transmission obligations for NITS customers cannot be met. In addition, there are serious concerns about the flexibility of this plan to accommodate economic power exchanges, provide backup for renewable generation during periods of curtailment and accommodate unexpected load growth.

24. Q. WHY DOES THE ILLUSTRATIVE GENERATION EXPANSION PLAN WITHOUT GREENLINK INCLUDE GENERATOR LEAD LINES FROM BOTH ESMERALDA AND LANDER?

A. There are potentially adequate renewable resources at Esmeralda to meet the resource requirements for northern Nevada. Placing all of the resources at Esmeralda would eliminate the need for a generator lead line from Lander. However, this would result in up to 1,200 MW of generation on a single radial generator lead line. A N-1 contingency that resulted in the loss of this line would result in the loss of 1,200 MW of generation in northern Nevada. This would overload the remaining tie lines in northern Nevada likely resulting in a collapse of the northern Nevada system. This would be a violation of the NERC transmission

planning criteria and, therefore, the generation lead line from Lander is also required.

25. Q. DOES THE GREENLINK PROJECT MEET THE REQUIREMENTS TO BE DESIGNATED AS A CRITICAL FACILITY?

A. Yes. The Commission may designate a facility as a critical facility for the purpose of:

- (a) Protecting reliability;
- (b) Promoting diversity of supply and demand side sources;
- (c) Developing renewable energy resources;
- (d) Fulfilling specific statutory mandates;
- (e) Promoting retail price stability; or
- (f) Any combination of paragraphs (a) through (e), inclusive.

In fact, the Commission has already designated Greenlink North and the Harry Allen to Northwest 525 kV project as critical facilities.³ As I discuss above, NV Energy has an obligation to maintain required system reliability. The Greenlink project is required to protect system reliability. All recent transmission planning studies have included the Greenlink project. Without the Greenlink project, it may not be possible to comply with mandatory reliability standards and the system would not have the required level of flexibility to respond to potential system contingencies. The Greenlink project promotes diversity of supply by allowing for the interconnection of a diverse range of resources including additional renewable energy resources and conventional thermal generation. It also allows for the transfer of energy between northern and southern Nevada. Greenlink is critical to the development of additional renewable energy resources. It provides access to

³ Docket No. 21-06001, November 26, 2022, Order at 9-10.

renewable energy resources located at located at Amargosa, Esmeralda and Lander substations. For the illustrative generation expansion without Greenlink plan, it was still necessary to build 2/3 of the Greenlink West and half of Greenlink North projects to access these resources. The Greenlink project is needed to fulfill statutory mandates. It is needed to comply with the Renewable Energy portfolio standard and it is also needed to comply with FERC OATT provisions that require transmission expansion to provide additional system import capacity for NITS customers. The Greenlink project is needed to promote retail price stability. It allows for the development of the most economic portfolio of generation resources. As shown in the Economic Analysis section of the filing and in Brattle's analysis, it also allows for the economic exchange of power between northern and southern Nevada and external markets resulting in substantial cost savings for retail customers. Therefore, the Commission should designate the remaining portions of Greenlink as critical facilities, which include Greenlink West and common ties.

26. Q. WHAT ACTION DO YOU RECOMMEND THE COMMISSION TAKE CONCERNING THE GREENLINK TRANSMISSION PROJECT?

A. I recommend that the Commission approve the revised project budget. There is no other project that can provide the benefits associated with the Greenlink project at a lower cost.

Transmission system network upgrades:

27. Q. WHY IS THE TOLSON SUBSTATION 330 MVA 230/138 KV TRANSFORMER REQUIRED?

A. The Tolson 336 MVA 230/138 kV transformer was identified in the 2023 NERC TPL-001-5 corrective action plan. This second transformer will mitigate the overloads associated with each of the various P1 (N-1) events observed in the 2027 sensitivity planning case. The Companies are requesting approval to install a second transformer at Tolson substation required per transmission planning standards, and native load growth. The estimated cost of the Tolson substation transformer is \$9.6 million.

28. Q. WHY IS THE REID GARDNER-HARRY ALLEN 230 KV TRANSMISSION LINE #3 REQUIRED?

A. The new 230 kV line will double the firm transmission capacity between the Reid Gardner and Harry Allen from 860 MVA to 1720 MVA. The #3 transmission line will be financially secured by a large generator interconnection customer as is required per the customer's LGIA. The area around Reid Gardner has over 3,500 MW of large renewable generation projects that have requested interconnection at Reid Gardner. Reid Gardner – Harry Allen transmission unsubscribed capacity is less than 50 MW. This new 230 kV line will provide an opportunity for 860 MW of renewable generation to become viable alternatives in future resource plans. The permitting of Reid Gardner – Harry Allen 230 kV line #3 was previously approved in Docket 22-11032 NPC/^{SP}PC 4th Amendment to the 2021 Integrated Resource Plan. The estimated cost of the transmission line is \$24.2 million.

29. Q. DOES THE CONSTRUCTION OF THE REID GA-DNER - HARRY ALLEN #3 TRANSMISSION LINE CAUSE A RELIABILITY ISSUE?

A. Yes. The construction of Reid Gardener – Harry Allen 230 kV line #3 line creates a NERC TPL-001-5 P7 violation, a N-2 contingency loss of Reid Gardner – Harry

Allen #1 and Reid Gardner – Harry Allen #2 230 kV lines. The #1 and #2 lines are on double circuit structures near Harry Allen. A single structure failure of one of these double circuit poles causes an overload of the new Reid Gardner – Harry Allen #3 230 kV line. This violation will be mitigated by separating the Reid Gardner – Harry Allen #1 and Reid Gardner – Harry Allen #2 230 kV lines onto single circuit structures.

30. Q. WHY IS THE LANTERN-COMSTOCK MEADOWS 345 KV LINE REQUIRED?

A. The Lantern – Comstock Meadows 345 kV line is an important part of the Tahoe-Reno Industrial Center (TRIC)/Fernley area master plan for load service and new generation resources. The need for this project is also discussed by Mr. Maxfield. This line's permitting was approved as part of the Fernley Area Master Plan in Docket No. 22-11032. The new line will be routed to pass adjacent to the future Vaquero substation, Veterans substation, and the existing Chukar substation, and future Viking substation so that the line can be folded into these substations as the loads require it. Sierra Solar generation is limited to 400 MW until Lantern - Comstock Meadows 345 kV line is in service. The Companies have entered into large generator interconnect agreements for the Sierra Solar 1,000 MW projects that requires the construction of Lantern – Comstock Meadows 345 kV line to deliver the generation reliably. Lantern – Comstock Meadows is also a contingent facility for several large Rule 9 customers who have recently signed their high voltage distribution (HVD) and or master planned community (MPC) agreements. The estimated cost of the Lantern-Comstock Meadows 345 kV line is \$105.0 million.

1 **31. Q. WHY IS IT NECESSARY TO ADD 230 KV CIRCUIT BREAKERS AT**
2 **MACHACEK SUBSTATION?**

3 A. The current configuration of Machacek substation does not provide reliable service
4 to customers served from the substation. Any time there is an outage of the Frontier-
5 Gonder 230 kV line, service to the entire Machacek substation is interrupted. This
6 substation serves up to 28 MW of load. The Frontier-Gonder 230 kV line is 115
7 miles long resulting in substantial line exposure and potential for line outages. Since
8 2012, there have been 7 forced outages of this line with 5 of the outages resulting
9 in a sustained outage of around 3 hours each. In addition, there have been 39
10 planned outages for line maintenance resulting in a temporary outage while line
11 switching is performed. Mt. Wheeler REA has continued to express concern about
12 the reliability of service to the Machacek substation and outages of their customer
13 load that could be avoided.

14
15 **32. Q. HAS NV ENERGY PREVIOUSLY REQUESTED COMMISSION**
16 **APPROVAL FOR THIS PROJECT?**

17 A. Yes. In the Third Amendment to the 2018 Joint Integrated Resource Plan
18 designated as Docket No. 19-06039, NV Energy requested approval to install three
19 new 230 kV breakers in a ring bus configuration at the Machacek 230 kV
20 Substation to improve reliability and safety. In that Docket, the Commission found
21 that the need to install a new 230 kV ring bus at Machacek 230 kV substation was
22 not adequately justified. The Commission also found that replacement of the
23 current motor-operated switches with new properly functioning motor-operated
24 switches is the most economical way to increase reliability and address safety
25 concerns. The Commission also indicated that nothing in the order precludes NV
26
27

Energy from proposing its preferred solution in an appropriate resource planning proceeding.

33. Q. DOES NV ENERGY HAVE AN OBLIGATION TO IMPROVE THE RELIABILITY OF MACHACEK SUBSTATION?

A. Yes. Per the NV Energy Open Access Transmission Tariff (OATT) and Federal Energy Regulatory Commission (FERC) policy, NV Energy has an obligation to provide transmission service to all transmission customers on a non-discriminatory basis. There is no other location on a major path on the NV Energy system where a single line outage will result in the interruption of this magnitude of load. Mt. Wheeler pays the same transmission rate as other transmission customers but does not receive the same level of reliable service as other customers. The addition of new properly functioning motor-operated switches will not prevent any of these outages. The new switches would allow for more rapid restoration of service during a sustained outage. NV Energy is committed to resolving the customer's concerns, increasing customer satisfaction, and improving transmission system reliability.

34. Q. WHAT RELIABILITY IMPROVEMENTS DOES NV ENERGY RECOMMEND AT MACHACEK SUBSTATION?

A. NV Energy's preferred alternative to provide Machacek substation with a similar level of reliability as other substations on the NV Energy system is the installation of a 3-breaker ring bus at Machacek substation. A lower cost alternative would be to install two 230 kV line breakers at Machacek substation. One breaker on the Machacek-Gonder #2302 230 kV line and a second breaker on the Machacek-Frontier #2306 230 kV line. This two-breaker alternative would provide the same level of reliability for the Machacek substation load as the 3-breaker ring bus at a

lower cost. The disadvantage of the two-breaker alternative is that, anytime maintenance is required on either breaker, it would be necessary to open the 230 kV line between Machacek substation and either Frontier substation or Gonder substation. This 230 kV line is a major path and the primary northern Nevada interconnection with PacifiCorp and The Los Angeles Department of Water and Power. It should not be necessary to open this path when breaker maintenance is required. The estimated cost for the breaker additions is \$14.8 million for the 3-breaker ring bus and \$7.0 million for two line breakers.

35. Q. WHY IS THE FT. CHURCHILL-COMSTOCK MEADOWS 345 KV TRANSMISSION LINE #2 REQUIRED?

A. The Ft. Churchill - Comstock Meadows 345 kV line #2 will be the second 345 kV line constructed between Ft. Churchill and Comstock Meadows and is required for a new Rule 9 customer load. Mr. Maxfield's testimony also discusses the need for this project. The new 345 kV line #2 will provide the required redundancy and capacity to the region's 345 kV system in and around the TRIC. The Ft Churchill – Comstock Meadows 345 kV #2 line is also a contingent facility for multiple new large load customers queued in the area. The #2 line is approved to be permitted as part of the Greenlink West project. The estimated cost of the line is \$110.2 million.

36. Q. WHY ARE THE FT. CHURCHILL 525/345 KV TRANSFORMERS #3 AND #4 REQUIRED?

A. When the load on the Ft Churchill 525/345 kV transformers #1 and #2 reaches 600 MVA, the third transformer will be required. Likewise, the fourth transformer will be required when Ft Churchill 525/345 kV transformers load reaches 1,200 MVA. This is required to accommodate the N-1 loss of a single 600 MVA transformer at

Ft. Churchill substation, per NERC TPL-001-5 planning standard. The estimated cost for these transformers is \$12.0 million for each transformer. Mr. Maxfield's testimony also discusses the need for this project.

37. Q. WHY IS PERMITTING FOR THE FT. CHURCHILL-VETERANS 525 KV TRANSMISSION LINE REQUIRED?

A. The Ft Churchill – Veterans 525 kV line will provide the necessary capacity for the Master Planned Community's (MPC) Rule 9 customers phase of an additional 1,125 MW load at Mackay and Goose substations and is required when the load exceeds the first phase's 900 MW between Gosling switching station and Mackay substation. The Mackay, Goose, and Veterans 525/345 kV transformers are also required for the MPCs and subsequently queued Rule 9 customers, to provide the needed 345 kV system redundancy and capacity for both 525 kV and 345 kV systems at the forecast full loads. The modularity of this plan will allow construction to be phased as the MPC loads grow. Annual NERC TPL-001-5 studies will provide an annual review to determine whether the new 525 kV line, transformers, and line folds into Mackay and Goose substation can be postponed or when the 525 kV line, substations, and transformers are required. To meet the customers' proposed load forecast, the permitting and siting of the 525 kV line must commence, like the permitting already approved and underway for the TRIC area master plan. The 525 kV line will be integrated in the area master plans and can be implemented in phases as the loads develop. The exact location of the load growth will impact in which substation the transformers should be sequenced and constructed to be the most beneficial. The project budget for permitting this line is \$14.0 million. Mr. Maxfield's testimony also discusses the need for permitting this project.

1 **38. Q. WHY IS THE VALMY 345 KV TERMINAL NEEDED FOR THE VALMY**
2 **COMBUSTION TURBINES?**

3 A. The interconnection of the two new combustion turbines totaling 411 MW at Valmy
4 will require the addition of a shared 345 kV lead line terminal at the North Valmy
5 substation 345 kV bus. This new position will require the bus and substation yard
6 to be expanded with new breakers and disconnect switches. The estimated cost for
7 the new terminal is \$5.22 million.

8
9 **39. Q. WHY IS HARRY ALLEN 230 KV BUS POSITION REQUIRED FOR THE**
10 **200 MW SOLAR AND BATTERY PROJECT?**

11 A. The interconnection of the Dry Lake East II PV/BESS 200/200 MW at Harry Allen
12 230 kV bus will require a new terminal at Harry Allen. This new position will also
13 require new breakers and disconnect switches. The estimated cost for the new
14 terminal addition is \$4.0 million.

15
16 **40. Q. WHY IS A NEW 345 KV TERMINAL POSITION AT FT. CHURCHILL**
17 **NEEDED FOR THE 700/700 MW SOLAR AND BATTERY**
18 **INTERCONNECTION LEAD LINE?**

19 A. The interconnection of the Libra PV/BESS 700/700 MW at Ft Churchill will
20 require a new 345 kV terminal position at Ft. Churchill. This new position will also
21 require new breakers and disconnect switches. The estimated cost for the new
22 terminal addition is \$3.9 million.

23
24 **41. Q. WHY IS A NEW 345 KV TERMINAL POSITION AT LANTERN NEEDED**
25 **FOR A 115 MW GEOTHERMAL PROJECT?**

26 A. The 115 MW Corsac Geothermal project will be interconnected at the Lantern 345
27 kV substation. This project is contingent on the Lantern – Comstock Meadows 345

kV line project. The Corsac Geothermal project will require a new 345 kV terminal position at Lantern substation. This new position will also require new breakers and disconnect switches. The estimated cost for the new terminal addition is \$2.0 million.

42. Q. WHAT IS THE CURRENT STATUS OF THE MIDPOINT TO ROBINSON SUMMIT 525 KV TRANSMISSION LINE (SWIP-NORTH)?

A. The SWIP-North project is a 285-mile long 525 kV transmission line from Midpoint substation on the Idaho Power Company system to the Robinson Summit substation on the NV Energy system. The project is being developed by LS Power and is forecasted to be in service in 2027. The project has been conditionally approved by the California Independent System Operator (CAISO), subject to Idaho Power Company participation. Under the proposed agreement, Idaho Power Company would contract for 500 MW of northbound capacity from Harry Allen to Midpoint. CAISO would contract for the balance of LS Power's capacity from Harry Allen to Midpoint and all of LS Power's southbound capacity from Midpoint to Harry Allen. The cost and ownership of SWIP-North will be 100 percent LS Power's responsibility.

43. Q. HOW WILL CONSTRUCTION OF THE SWIP-NORTH PROJECT IMPACT NV ENERGY TRANSMISSION CAPACITY ENTITLEMENTS?

A. In accordance with the Transmission Use Agreement (TUA) between LS Power and NV Energy, when SWIP-North is completed, NV Energy will receive capacity entitlements on the SWIP-North project and revised capacity entitlements on ON Line. NV Energy's capacity entitlement on SWIP-North will be 952.5 MW north to south and 847.5 MW south to north. NV Energy currently has 100 percent of the

capacity on ON Line. The ON Line capacity is currently limited to 900 MW north to south and 600 MW south to north. With the completion of SWIP-North, NV Energy's capacity entitlement on ON Line will increase to 1,217.5 MW north to south and 1,172.5 MW south to north. This additional transmission capacity may be used to purchase wind or other resources at Midpoint.

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

A. Yes.

EXHIBIT POTTEY-DIRECT-1

STATEMENT OF QUALIFICATIONS

CHARLES A. POTTEY

My name is Charles A. Pottey. My business address is 6100 Neil Road, Reno, Nevada. I am the Director of Transmission Planning for Nevada Power Company, dba NV Energy and Sierra Pacific Power Company, dba NV Energy.

I graduated from Rensselaer Polytechnic Institute with a Bachelor of Science Degree in Electric Power Engineering in 1975, and a Master of Engineering Degree in Electric Power Engineering in 1977.

I am a registered Professional Engineer in Colorado.

Since September of 2021 I have been employed as the Director of Transmission Planning. I am responsible for all transmission associated with integrated resource plans (“IRP”), compliance, generator interconnections and transmission service requests, including load addition functions for the Companies. I am also responsible for regional and inter-regional transmission planning.

From April of 2015 until April of 2017, I was employed as the Director of Transmission Policy, Contracts and Business Services. I serve as the primary contact for new transmission customer requests for interconnections to the transmission grid. I ensure compliance with applicable regulations and response deadlines associated with the Open

Access Transmission Tariff (OATT). My staff negotiates and finalizes contracts with transmission customers for addition and withdrawal of generation interconnections, transmission service, ancillary services and agreements for co-owned facilities. I lead the billing and settlement function of the energy imbalance market entity and OATT.

From April 2010 until April of 2015, I was employed as the Manager of Network and IRP Transmission Planning. I was responsible for leading a staff of engineers who perform transmission system analyses to evaluate the operation of Sierra's and Nevada Power's system and analyze required system additions. I recommended optimal transmission additions considering economics, feasibility, performance, and reliability of alternatives to provide reliable and economical electric service to Sierra and Nevada Power customers. I oversaw the evaluation of the long-range needs of the electric transmission system including capacity, reliability, voltage regulation, stability and operation during contingency conditions to ensure compliance with all NERC and WECC transmission planning reliability requirements. I managed the preparation of the Transmission section of the Integrated Resource Plan and Energy Supply Plan filings.

From December 2004 until April 2010, I was employed as the Manager of the Long-Term Resource Planning. I was responsible for directing technical analysis to evaluate the capital cost, production cost, and reliability of various transmission, generation, purchase power, and demand side alternatives to ensure sufficient electric resources are available to provide reliable and economical electric service to Sierra Pacific Power and Nevada Power customers. I managed the preparation of the Integrated Resource Plan and

Energy Supply Plan filings. I directed the development of detailed system modeling to accurately represent system operating constraints including system transmission limitations for production costing studies of existing and future power supply options.

From February 2002 until December 2004, I was employed as principal consultant in Sierra's Long-Term Resource Planning Department. I was responsible for developing analysis of various resource options to ensure sufficient resources are available to reliability and economically serve Sierra and Nevada Power's electric customers.

From June 2000, until February 2002, I was employed as a Senior Rate Engineer in Sierra's Rates and Regulatory Affairs Department. I am responsible for preparing price analysis and developing rates for electric, gas and water services offered by Sierra Pacific and Nevada Power.

From January 1991 until June 2000, I was employed as a Senior Engineer in Sierra's Resource Planning department. I was responsible for performing technical analyses to evaluate the capital cost, production cost, and reliability of various generation, purchase power, and demand side alternatives to ensure sufficient electric resources are available to provide reliable and economical electric service to Sierra's customers. I developed detailed modeling of Sierra's system to accurately represent system operating constraints including system transmission limitations for production costing studies of existing and future power supply options. I have performed production costing, reliability, and economic analysis to evaluate the cost, benefits, and reliability of potential supply and demand side alternatives to satisfy specific future resource requirements. I have also

evaluated the economics and reliability of Qualifying Facilities, Independent Power Producers, and other non-Sierra owned generation options.

From August 1988 until January 1991, I was employed as a Senior Engineer in Sierra's Electric System Planning department. I was responsible for performing engineering studies to evaluate Sierra's long range and operational transmission and distribution system requirements. I performed powerflow and stability studies to evaluate the operation of Sierra's system and analyze required system additions and recommended optimal additions considering economics, feasibility performance, and reliability of the alternatives. I developed a loss evaluation procedure to calculate the present worth value of system losses. I evaluated system import and export constraints and prepared appropriate operating nomograms.

From November 1982 until August 1988, I was employed as a Senior Engineer in Sierra's Electric System Control Center. I was responsible for providing technical support to Sierra's Electric System Control Center to assure optimal system operation. I evaluated generation dispatch and scheduled power purchases to ensure Sierra system was operated in the most economic manner possible while maintaining required system reliability. I developed operating guidelines and procedures for transmission and distribution facilities.

From December 1979 until November 1982 McGraw Edison employed me as an Apparatus Engineer. I was Responsible for providing sales engineers, product

departments, and electric utility customers throughout the Rocky Mountain region with technical assistance on the application, installation, testing, and maintenance of McGraw Edison's complete line of electrical equipment.

From August 1978 until December 1979 Tri-State Generation and Transmission Association, employed me as a Project Engineer. I was responsible for coordinating all project activities for major substation and transmission line additions.

From May 1977 until August 1978 McGraw Edison Company employed me as a Power System Engineer. I was responsible for performing analytical studies for electric utility clients. I performed insulation coordination studies, calculated system unbalances, evaluated negative sequence currents, and analyzed transient recovery voltages.

AFFIRMATION

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

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

Date: May 31, 2024

Charles A. Pottey
CHARLES A. POTTEY

LAYNE M MAXFIELD

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 ____

Prepared Direct Testimony of

Layne M. Maxfield

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

A. Layne Maxfield, Manager Transmission System Planning at NV Energy. My business address is 6100 Neil Road, Reno Nevada 89511. I am filing testimony on behalf of Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, "NV Energy" or the "Companies").

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

A. I have 20 years of experience in the electrical utility industry, which includes engineering, project management and leadership roles. I worked as a technical advisor to Rocky Mountain Power's Project Management Office for seven years. I worked for two years as a senior transmission planning engineer. I have worked for approximately two years as Manager, Transmission System Planning, for NV Energy. In my current role, I have prepared transmission narrative for two Integrated Resource Plan (IRP) amendments and this current 2024 IRP filing. My statement of qualifications is attached as **Exhibit Maxfield-Direct-1**.

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

3 A. As the manager of transmission system planning, I supervise transmission planning
4 engineers, who complete interconnection studies and transmission service studies
5 as prescribed by the Federal Energy Reliability Council (FERC) approved Open
6 Access Transmission Tariff (OATT). I also contribute oversight for regulatory
7 compliance. I review and approve customer load studies as prescribed under Rule
8 9. I also coordinate area master planning and ensure consistency of transmission
9 study's results with the transmission area master plans.

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

14 A. I have not previously submitted pre-filed testimony with the Commission.

15
16 **5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

17 A. I sponsor the transmission projects that are required for new and existing customer
18 load growth. These include new customers connecting to the transmission system
19 and the 230/12 kilovolt (“kV”) substations for native load growth.

20 1. Lantern – Comstock Meadows 345 kV line

21 2. Comstock Meadows 280 MVA 345/120 kV transformer #2

22 3. West Tracy 280 MVA 345/120 kV transformer #1

23 4. Darling substation with two (2) 37 MVA 230/12 kV transformers

24 5. Log Cabin substation with one (1) 37 MVA 230/12 kV transformers

25 6. Spring Canyon substation three (3) 37 MVA 230/12 kV transformers

7. Ft Chruchill-Comstock Meadows 345 kV line #2 and Ft Chruchill third and fourth 600 MVA 525/345 kV transformers
8. Mackay 345 kV switching station
9. Gosling 345 kV switching station
10. Ft Chruchill – Veterans 525 kV line
11. Naniwa 345 kV switching station
12. Nighthawk 345/120 kV substation
13. Vaquero 345/120 kV substation
14. Viking 345 kV switching station
15. Veterans 345/120 kV substation
16. Prospector 230 kV line terminal

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

A. I am sponsoring

Exhibit Maxfield-Direct-1 – Statement of Qualifications.

I am sponsoring or co-sponsoring the following Technical Appendices:

- Technical Appendix **TRAN-2** – Apex Area Master Plan
- Technical Appendix **TRAN-3** – Western Nevada Master Plan
- Technical Appendix **TRAN-4** – Agreements List

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

A. No.

8. Q. **HOW IS YOUR TESTIMONY ORGANIZED?**

A. I discuss the Companies' need to construct each of the required transmission system network upgrades to maintain the system reliability while serving new and native load growth.

9. Q. **WHY IS THE LANTERN – COMSTOCK MEADOWS 345 KV LINE REQUIRED?**

A. Multiple executed Rule 9 agreements require the Lantern – Comstock Meadows 345 kV line to be constructed to provide the required transmission capacity and reliably. These include the HVD (High Voltage Distribution) loads between Fernley and the Tahoe Reno Industrial Center (TRIC). The Lantern – Comstock Meadows 345 kV line provides the opportunity to create multiple 345/120 kV substations when the loads require them, for example, the Chukar 345/120 kV substation. Connecting to Chukar leverages the 120 kV transmission system which has already been constructed. This 345/120 kV connection will also provide increased capacity and reliability to the existing 120 kV HVD customers in TRIC. This line has been identified in many load studies and generator interconnection studies. Even though the line was first planned to interconnect the Sierra Solar 1,000 MW of generation under a Large Generator Interconnection Agreement (LGIA) and Network Integrated Transmission Service Agreement (NITSA). Lantern – Comstock Meadows 345 kV line is a contingent facility for multiple customers and considered integral to the area transmission master plan, therefore, it should go forward with or without Sierra Solar's phase II. Technical Appendices TRAN-3, which is the area master plan, and TRAN-4 list the agreements and customer requests that require Lantern – Comstock Meadows 345 kV line.

10. Q. **WHY IS THE COMSTOCK MEADOWS 280 MVA 345/120 KV TRANSFORMER #2 REQUIRED?**

A. Existing customers' Rule 9 agreements require the Comstock Meadows 280 MVA 345/120 kV transformer #2 be constructed to provide the required transmission capacity and reliability. Using the existing customers load forecasts, this transformer will be required in 2028, which is the soonest it could be completed based on the long lead time of power transformers. Specifically, this transformer is required to serve an existing customer taking delivery at Comstock Meadows. But it is also required to serve subsequent customers' requests. It also benefits TRIC loads at the Wild Horse substation. The new transformer also increases the capacity of the Tracy area's existing 120 kV transmission system. Technical Appendix TRAN-4 lists the agreements that require Comstock Meadows 280 MVA 345/120 kV transformer #2.

11. Q. **WHY IS THE WEST TRACY 280 MVA 345/120 KV TRANSFORMER #1 REQUIRED?**

A. New and native load forecasts require West Tracy 280 MVA 345/120 kV transformer #1 (second 345/120 kV) to be constructed to provide the required transmission capacity and reliability. With the existing load forecasts, this transformer will be required in 2028. Based on the long lead time of power transformers, the manufacturer deposits will be required inside this three-year action plan. Specifically, this transformer is required to serve 120 kV HVD customers inside TRIC because of increasing load forecasts. As loads grow at Comstock Meadows, Wild Horse, Chukar and Dove, the 120 kV transmission system will require an additional 345/120 kV capacity for N-1 conditions. This is combined with a new 120 kV line from West Tracy substation and a new line fold

of an existing 120 kV line into the Wild Horse substation. The new transformer increases the total capacity of Tracy area's existing 120 kV transmission system. Technical Appendix TRAN-4 lists the agreements that require West Tracy 280 MVA 345/120 kV transformer #1, which is the second 345/120 kV transformer at West Tracy substation. This transformer in-service date can be delayed if the loads fail to materialize as forecast.

12. Q. WHY IS THE DARLING 230/12 KV SUBSTATION REQUIRED?

A. Load growth on the northwest side of the Las Vegas valley will require an additional 230/12 kV distribution substation to relieve distribution circuits and transformers at Elkhorn substation in 2028. There are also distribution service requests that will require Darling to be constructed before June 1, 2028. While the energization of this new substation is outside the three-year action plan, transformer manufacturer deposits and engineering will need to be funded within this three-year action plan.

13. Q. WHY IS THE LOG CABIN 230/12 KV SUBSTATION REQUIRED?

A. Load growth on the northwest side of the Las Vegas valley will require an additional 230/12 kV distribution substation to relieve distribution circuits and transformers at Northwest substation in 2028. There are also distribution service requests that will require Log Cabin to be constructed before June 1, 2028. While the energization of this new substation is outside the three-year action plan, transformer manufacturer deposits and engineering will need to be funded within this three-year action plan.

14. Q. **WHY IS THE SPRING CANYON 230/12 KV SUBSTATION REQUIRED?**

A. Several new customers are requesting distribution service for their Master Planned Communities (MPC agreements) in the Eldorado Valley, but there is no distribution substation in this area that is capable of serving the magnitude of loads being requested. Fortunately, there is an existing 230 kV line in the Eldorado Valley that can be folded into Spring Canyon substation which will significantly reduce the time and cost to serve this new load. The customers are requesting service dates as early as 2024; however, the feasible in-service date of Spring Canyon is early 2026 due to the long lead time of transformers and breakers.

15. Q. **WHY ARE THE FT CHURCHILL – COMSTOCK MEADOWS 345 KV LINE #2 & ASSOCIATED THIRD AND FOURTH 600 MVA 525/345 KV TRANSFORMERS REQUIRED?**

A. There is a specific customer requesting 461 MW that will require the construction and line fold of the Ft Churchill – Comstock Meadows 345 kV line #2 into the Mackay switching station. The Ft Churchill-Comstock meadows 345 kV line #1 construction was already approved in Docket 20-07023, another customer has requested 450 MW to be served by folding the #1 line. Permitting, land acquisitions and design of Ft Churchill-Comstock meadows 345 kV line #2 was also approved in Docket 20-07023. There are also two loads that require the #2 line, one is a 450 MW load, and the other is 625 MW. These two customers are both to be served through line folds of the West Tracy – Comstock Meadows 345 kV line into Naniwa switching station and Gosling substation. In addition to these loads, there are several other loads in TRIC that, should they go forward, will require the addition of 525/345 kV transformers and the new Ft Churchill – Comstock Meadows #2 345 kV line to provide the capacity and reliability necessary per the

NERC TPL-001 transmission planning standard. The current customer forecasts indicate load on the first two Ft Churchill 525/345 kV transformers, which are part Greenlink West, will exceed the transformers' continuous N-1 600 MVA rating within the three-year action plan. This potential violation necessitates the construction of a third Ft Churchill transformer in this three-year action plan. Based on the customer load forecasts, it is also identified that a manufacture's deposit on the fourth transformer will be required inside the three-year action plan.

16. Q. WHY IS THE MACKAY 345 KV SWITCHING STATION REQUIRED?

A. There is a master planned data center developer requesting a total of 1,125 MW at this site, the first phase of which is 450 MW. This first phase's new load will require the Ft Churchill – Comstock Meadows 345 kV line #1 and #2, the Lantern – Comstock 345 kV line and the West Tracy – Comstock Meadows 345 kV line. The first phase will require the Mackay 345 kV switching station, which will be a line fold of the Ft Churchill – Comstock Meadows 345 kV line #1. The customer will be taking delivery at 345 kV, as they requested. In the customer's second phase, adding 765 MW will require 525/345 kV transformers at Mackay and the Ft Churchill-Mackay-Goose-Veterans 525 kV line.

17. Q. WHY IS THE GOSLING 345 KV SWITCHING STATION REQUIRED?

A. There is a specific master plan data center developer requesting a total of 810 MW of which the first phase is 450 MW. This first phase's new load will require the West Tracy – Comstock Meadows 345 kV line #1 and #2, the Lantern – Comstock 345 kV line and the West Tracy – Comstock Meadows 345 kV line. The first phase will require the Gosling 345 kV switching station, which will be connected by a line fold of the West Tracy – Comstock Meadows 345 kV line. The customer will

be taking delivery at 345 kV as they requested. In addition, the customer's second phase adding 360 MW will require 525/345 kV transformers at Goose substation, (which is near Gosling) and will also require the Ft Churchill-Mackay-Goose-Veterans 525 kV line.

18. Q. WHY IS THE PERMITTING OF FT CHURCHILL – VETERANS 525 KV LINE REQUIRED?

A. For this project, the Companies request approval of permitting only. There is a master planned data center, which at two sites of 1,215 MW and 810 MW called Mackay and Gosling/Goose respectively, will require a 525/345 kV service at Mackay, Goose and Veterans. The Ft Churchill – Veterans 525 kV line will be routed such that it can be folded into Mackay and Goose, when it becomes necessary for each sites' phase two build out, 765 MW and 360 MW respectively.

In addition, several subsequent customer requests that have identified Ft Churchill – Veterans 525 kV line as a contingent facility. Thus, even if this specific customer does not develop as planned, the 525 kV line will still be required.

Due to the long lead time required to permit this line, the Companies are requesting that permitting be approved in this filing. The Companies will delay the line and Veterans 525/345 kV transformer construction approval requests until a later filing. Construction timing will be reviewed on an annual basis to determine the precise year the line should be constructed based on load growth and customer load forecasts. The long lead time required to permit this 525 kV line necessities that it be started during this three-year action plan, based on the current customer load forecasts. The customer load forecasts are an input in determining NV Energy load

forecast. Customer load forecasts are not discounted but are instead corrected on an annual basis. The corrected customer forecasts drive the timing of the transmission projects required to meet customers' loads. As has been done historically, the Companies will continue to delay projects, if annual load forecasts are reduced, as possible and appropriate.

Importantly, this new 525 kV line will eliminate the need for two or three new 345 kV lines to achieve the same objective and at a lower overall total cost. This 525 kV line will use the already planned Ft Churchill Comstock Meadows 345 kV line #1 and #2, the Lantern – Comstock 345 kV line and the West Tracy – Comstock Meadows 345 kV line for N-1 redundancy. If the proposed loads go forward, even in part, cumulatively they will require the addition of Ft Churchill - Veterans 525 kV line and 525/345 kV transformers at Veterans to provide the capacity and reliability necessary per the NERC TPL-001 transmission planning standard.

19. Q. WHY IS THE NANIWA 345 KV SWITCHING STATION REQUIRED?

A. There is a specific customer which has signed a new Rule 9 agreement for High Voltage Distribution (HVD) load request of 625 MW to be served from a new Naniwa substation. This load magnitude requires the West Tracy – Comstock Meadows 345 kV line to be folded into the Naniwa 345 kV switching station. The transmission load study also identified as contingent facilities the Ft Churchill – Comstock Meadows 345 kV line #1 and #2, Lantern – Comstock 345 kV line, West Tracy – Comstock Meadows 345 kV line and Ft Churchill – Veterans 525 kV line.

20. Q. **WHY IS THE NIGHTHAWK 345/120 KV SUBSTATION REQUIRED?**

A. There is a specific customer which has signed a Rule 9 agreement for an HVD load request of 461 MW. The load magnitude requires the Ft Churchill – Comstock Meadows 345 kV line #2 to be folded into the Nighthawk 345/120 kV substation. The transmission load study also identified as contingent facilities the Lantern – Comstock 345 kV line and the West Tracy – Comstock Meadows 345 kV line. The customer will take delivery from the Nighthawk 120 kV bus. The 60 kV transmission near the customer site has significant constraints due to voltage issues and low capacity under N-1 contingencies. The new Nighthawk 120 kV bus will allow mitigations that resolve the constraints on the 60 kV system by constructing a 120/60 kV transformer at or near Silver Springs substation in the future. The Nighthawk 345/120 kV substation will also create an alternative 120 kV source for the planned Fallon – Lahontan - Eagle & Lahontan – Fallon 60 kV to 120 kV conversion, which could reduce the 60 to 120 kV conversion cost by reducing the length of lines that must be converted or replaced with 120 kV lines.

21. Q. **WHY IS THE VAQUERO 345/120 KV SUBSTATION REQUIRED?**

A. A specific customer is expected to sign a Rule 9 agreement for an HVD load request for 461 MW in this three-year action plan. The magnitude of the load requires the Lantern – Comstock Meadows 345 kV line to be folded into the new Vaquero 345/120 kV substation. The transmission load study also identified contingent facilities, including the West Tracy – Comstock Meadows 345 kV line and Ft Churchill – Comstock Meadows 345 kV line #1. The customer will take delivery from the Vaquero 120 kV bus as requested. The 120 kV transmission system near the customer site has significant constraints due to voltage issues under N-1 contingencies and low capacity for new loads. The new Vaquero 120 kV bus will

create a suitable alternative to the planned Veterans 345/120 kV substation, such that the 345/120 kV at Veterans could be delayed or cancelled if Vaquero goes forward in time. The Vaquero 345/120 kV substation will also create a strong 120 kV source for the planned Fallon – Lahontan - Eagle, Lahontan – Fallon 60 kV to 120 kV conversion, which could reduce the overall cost of the conversion by eliminating the need for Veterans 345/120 kV substation.

22. Q. WHY IS THE VIKING 345 KV SWITCHING STATION REQUIRED?

A. A specific customer who is expected to sign a Rule 9 agreement for an HVD load request of 461 MW in this three-year action plan. The load magnitude requires the Lantern – Comstock Meadows 345 kV line to be folded into the Viking 345/120 kV substation. The line fold will occur between Chukar and Comstock Meadows substation. The transmission load study also identified contingent facilities, including the West Tracy – Comstock Meadows 345 kV line and Ft Churchill – Comstock Meadows 345 kV line #1. The customer will take delivery from the Viking 345 kV bus because there is not enough remaining 120 kV transmission capacity near the customer’s site.

23. Q. WHY IS THE VETERANS 345/120 KV SUBSTATION REQUIRED?

A. A specific customer has signed a Rule 9 agreement for a Master Planned Community (MPC) load request of 70 MW. The load magnitude requires the Lantern – Comstock Meadows 345 kV line to be folded into the Veterans 345/120 kV substation because there is limited 120 kV capacity near Eagle Substation. The line fold will occur between Chukar and Vaquero/Lantern substation. If Vaquero 345/120 kV substation construction schedule allows, the Veterans 345/120 kV

portion could be delayed or cancelled. The need for Veterans 525/345 kV substation is independent of Vaquero 345/120 kV or Veterans 345/120 kV.

24. Q. WHY IS THE PROSPECTOR 230 KV LINE POSITION REQUIRED?

A. There is a specific customer which has signed a Rule 9 agreement for an HVD load request of 7 MW. The customer has requested delivery at 230 kV, therefore, the addition of a 230 kV line at Prospector substation is required.

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

A. Yes.

EXHIBIT MAXFIELD-DIRECT-1

Statement of Qualification

Layne M. Maxfield

My name is Layne M. Maxfield, I have 20 years of experience in the power industry. I have been the Manager of Transmission System Planning (Planning) for NV Energy since the fall of 2021. My direct reports are the planning engineers who perform the system impact studies for generator interconnections, transmission service and associated facilities studies. My direct reports perform the compliance studies and related work for NERC TPL and other requirements. I am also responsible for the transmission-to-transmission interconnection studies. I provide the final review and control of the transmission area master plans based on the customer load forecast and future transmission needs. I have prepared the transmission narrative for the 2024 integrated resource plan and two prior amendments. I create business practices for interconnection customers and transmission reliability standards for the company. I am responsible for coordinating transmission system planning efforts with all the NV Energy departments and outside entities.

From 2019 to 2021, I was a Senior and Senior II Transmission Planning Engineer for PacifiCorp and then NV Energy. I was Responsible for system impact studies for transmission system service requests. I was the lead for NV Energy's large generator interconnection cluster studies required under the Open Access Transmission Tariff (OATT). During which time the interconnection queue at NV Energy almost doubled. I was a planning area contributor to the annual PacifiCorp NERC TPL-001 study.

From 2013 to 2020 I was the technical advisor to PacifiCorp's Project Management Office (PMO). I supported the project managers in Idaho, Utah, and Wyoming. As part of this I managed all the construction contractors' outages, developing construction sequence plans for all major projects, coordinated construction efforts with operations, reviewed all commissioning documents for the electrical equipment and ultimately authorized energization of new equipment. I was the primary contributor to the update of the Rocky Mountain Power's Grounding Safety Procedure Manual. I received a Project Management Professional (PMP) certification from Project Management Institute (PMI).

From 2007 to 2013, I was the engineering department head at the City of Idaho Falls power division. Annually I created the ten-year capital plan for the entire municipal utility. I was the technical witness to the city council regarding the utilities' capital projects. I was a presenter at transmission line siting public outreach meetings and stake holder meetings. I participated in the recertification of the Gem State hydro project with FERC. I was the project manager for a 161 kV transmission line in the siting phase, generator protection relay upgrades, substation protection relay upgrades, transformer maintenance, new substations, cable replacement and rejuvenation, created the distribution system master plan, the 4 kV to 12 kV voltage conversion projects and retired four 4 kV substations. I was the lead to develop the utilities first distribution system model. Lead contributor in a Department of Energy funded smart grid demonstration project which included auto-restoration, using new smart meter communication infrastructure, and other pilot projects. I managed the field engineers and the inspectors, wherein I reviewed distribution designs and line extension estimates. Developed construction standards and transitioned the utility to construction material assemblies to aid the efficiency of engineering, procurement, warehouse, and construction. Procured engineering service contracts for large projects. I wrote equipment specifications for large equipment procurements.

In 2007 I became the System Engineer at Overton Power District #5 wherein I created system master plans for the distribution system, one of which was 3,000 homes. I managed the creation of the first distribution system model from the existing GIS data. Project manager of new substations wherein I

reviewed the substation engineering design. Performed studies to verify distribution system performance and planned mitigations as necessary. I was trained in substation engineering from the University of Wisconsin - Milwaukee.

2004 to 2007 I was a Field Engineer at Overton Power District #5, where I coordinated with customers to develop line extension plans and line extension estimates. Coordinated the customer payments with procurement to secure long lead time materials.

I received a bachelor's degree in electrical engineering from the University of Nevada Las Vegas in 2004. I received a professional engineer licensee in electrical engineering in the State of Idaho in 2008.

AFFIRMATION

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

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

Date: May 31, 2024


LAYNE M. MAXFIELD

SHAHZAD M LATEEF

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 ____

Prepared Direct Testimony of

Shahzad M. Lateef

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

A. My name is Shahzad M. Lateef. My current position is Senior Project Director,
Transmission Development for Nevada Power Company d/b/a NV Energy
("Nevada Power" or the "Company") and Sierra Pacific Power Company ("Sierra,"
and together with Nevada Power, the "Companies"). My business address is 6226
West Sahara, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I have been employed by the Companies for 29 years. I received my Bachelor of
Science degree in Electrical Engineering in 1994 and Master of Science degree in
Electrical Engineering in 1997. I began my career at Nevada Power as an engineer
in the Bulk Power Operations department in 1995. Since then, I have worked as an
engineer in Operational Planning, Resource Planning, Distribution Planning, and
Distribution Operations, and in various roles of increasing responsibility
(supervisor, manager, director, vice president) within Transmission and
Distribution System Operations. Prior to my current role as Senior Project Director
for Transmission Development, I was Vice President of Electric Delivery. I am a

registered professional engineer in the State of Nevada. A copy of my statement of qualifications is provided as **Exhibit Lateef -Direct1 – Statement of Qualification.**

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

A. I am currently the Senior Project Director of Transmission Development. In my role, I am responsible for overseeing the development of Greenlink Nevada Transmission.

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

A. Yes, I provided written testimony in fifth amendment to the Companies’ 2021 Integrated Resource Plan, 2020 Natural Disaster Protection Plan and previous Deferred Energy filings with the Commission. I have also participated in several workshops with the Commission associated with Docket No. 12-10013.

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

A. The purpose of my testimony is to provide an updated cost forecast for the Greenlink Nevada transmission project. I will also be providing the key reasons for the project cost escalation.

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

A. I am sponsoring or co-sponsoring the following Exhibits:
Exhibit Lateef - Direct 1 – Statement of Qualifications

Exhibit Lateef - Direct 2 – Greenlink Forecast Update – May 2024

7. Q. WHAT WAS THE ORIGINAL COST ESTIMATE FOR GREENLINK NEVADA TRANSMISSION AS APPROVED BY THE COMMISSION AND WHEN WAS IT PREPARED?

A. The original estimate for Greenlink Nevada transmission was prepared in 2019 and submitted in Docket No. 20-07023 on July 20, 2020. It was subsequently supplemented with revised cashflows on October 7, 2020, to reflect a modification in the sequence of in-service dates for Greenlink West and Greenlink North. Commission’s Order dated March 22, 2021, approved Greenlink West. The original estimate for the Greenlink projects was updated to include additional transmission and substation elements, including construction of Greenlink North, of the Transmission Infrastructure for a Clean Energy Economy Plan (“TICEEP”) pursuant to the Nevada Senate Bill 448 and filed with the Commission as an amendment to Docket No. 21-06001 on September 1, 2021. The Commission approved a stipulation to construct the TICEEP facilities on January 26, 2022. The estimated costs as approved by the Commission in Docket Nos. 20-07023 and 21-06001 were \$2,484 million. This included a 20 percent contingency and did not include Allowance for Funds Used During Construction (“AFUDC”).

8. Q. WHAT WAS THE BASIS FOR THE ORIGINAL ESTIMATE FOR GREENLINK NEVADA TRANSMISSION?

A. The original estimate was based on average per-mile cost of permitting, design, engineering, and construction for 525 kilovolt (“kV”) and 345 kV transmission lines, and average cost of substation materials and construction based on similar past projects. The original estimate was developed based on a proposed

transmission line route, prior to Bureau of Land Management's ("BLM") permitting process and determination of final transmission line route and substation locations. The original estimate was also based on preliminary engineering assessment prior to development of detailed engineering studies and design specifications.

9. Q. WHAT IS THE MOST RECENT COST ESTIMATE FOR GREENLINK NEVADA TRANSMISSION?

A. As of May 2024, the Companies estimate the cost of the Greenlink Nevada transmission project to be \$4,239 million. This represents an increase of \$1,755 million (70.6 percent) over the original estimate of \$2,484 million approved by the Commission in Docket Nos. 20-07023 and 21-06001. The updated estimate includes a \$416 million contingency. This updated estimate adds to the originally estimated project cost \$340 million in escalation, \$252.1 million in costs caused by the project scope changes, and \$101 million in sales and use taxes. Inflation has played a major role in the price escalation. Development of detailed engineering design and changes to the scope of the project compared to what was originally estimated also contributed to an increase in project cost forecast. In line with the original estimate, the updated estimate does not include AFUDC.¹

10. Q. WHAT IS THE BASIS FOR THE REVISED ESTIMATE FOR THE GREENLINK NEVADA TRANSMISSION PROJECT?

A. The revised estimate for the Greenlink Nevada transmission project is based on contracts and final proposals for all long-lead-time materials and construction of transmission lines, substations and telecommunications infrastructure. The revised

¹ Prepared Direct Testimony of John Tsoukalis, The Brattle Group, also presents this cost increase data in Figure PF-8.

1 estimate includes a contingency of \$416 million based on Monte Carlo analysis of
2 strategic risks with 75 percent confidence interval.

3
4 The revised estimate adds to the original estimate an estimated \$340.8 million in
5 cost escalation through the completion of the projects in December 2028. The cost
6 escalation is based on several items including increases in contractual labor rates
7 per the International Brotherhood of Electric Workers Local 396 and Local 1245
8 contracts with NV Energy. The material/equipment cost escalation tracks
9 commodity indices and is based on an estimated 3.5 percent per year increase. The
10 combined labor and material escalation results in an increase of \$340.8 million in
11 the total project forecast. This category of forward-looking costs was not included
12 in the original Greenlink estimate or the updated estimate provided in Docket No.
13 23-08015.

14
15 The revised estimate also adds to the original estimate \$97.4 million for the
16 construction of Fort Churchill–Comstock Meadows #2 345 kilovolt (“kV”)
17 transmission line. Commission approval of this component is being separately
18 requested in this Joint Application. The Commission had originally approved
19 permitting and preliminary engineering only for the Fort Churchill–Comstock
20 Meadows #2 transmission line in the amount of \$12.8 million. The construction
21 cost of this line was not included in the original Greenlink estimate or the updated
22 estimate provided in Docket No. 23-08015.

23
24 The Bureau of Land Management has stipulated use of H-Frame structures in
25 expanded Desert Tortoise and Sage Grouse habitats. This has resulted in an
26 additional 160 miles of H-Frame structures. The cost of H-Frame structures is 42

percent higher than cost of guyed-V lattice structures originally planned. The cost difference is based on shorter span length and higher cost of materials associated with H-Frame structures. This environmental risk mitigation has resulted in an increased cost of \$124 million for the project.

The updated forecast also includes an estimated \$20 million for Nevada Sage Grouse habitat mitigation, \$9 million for federal land wilderness characteristics mitigation and \$1.7 million for Desert Tortoise Section 7 mitigation.

The revised estimate also includes \$101 million in sales and use taxes based on planned procurement of materials. This cost category was not included in the original Greenlink estimate or the updated estimate provided in Docket No. 23-08015.

Combined, the contingency (\$416 million), escalation from 2024 through 2028 (\$340.8 million), construction of Fort Churchill–Comstock #2 transmission line (\$97.4 million), increase in the use of H-Frame structures (\$124 million), increased environmental mitigation required by the Bureau of Land Management (\$30.7 million), and sales and use taxes (\$101 million) represent \$1,109.9 million in costs as represented in this updated forecast.

11. Q. WHAT IS THE REASON FOR USING INDICES FOR THE PROPOSALS?

A. Due to supply chain disruptions witnessed in 2020 through 2023, the commodity (e.g. steel, copper, aluminum, fuel) prices fluctuated widely during the period. In order to prevent potential bidders from including the commodity volatility risk in their proposals for this long-term project and considering that several commodity

prices have receded from their highest levels, the Companies requested that the bidder proposals to be tied to an agreed-upon and specific commodity index that relate to bidder proposal. The bidder proposals are based on index value on the date of the proposal. If the index value increases or decreases from the date of the proposal, the bidders will increase or decrease their overall proposal value. In this forecast, the Companies have included an estimated 3.5 percent per year increase in the value of all indices.

12. Q. WHAT IS THE DIFFERENCE BETWEEN PRELIMINARY AND FINAL PROPOSALS?

A. The Companies prepare and publish a request for proposals including a detailed technical specification to prospective bidders. After the preliminary proposals are received, the Companies engage in a thorough technical review of the proposals. As a part of the technical review, the Companies ask further clarifying questions for the items included in the proposals. The Companies also evaluate and answer any exceptions noted in the proposals. After completion of technical reviews, the Companies seek “best and final” bid price associated with the proposals from all technically qualified bidders. The lowest cost technically qualified bidder is selected for the award of the contract. To date, the Companies have awarded the contracts to the lowest cost technically qualified providers for all materials and services that it has received proposals for. Upon award of the contract, the Companies engage in contract negotiations where further design optimizations or changes to delivery or construction schedule may be considered, resulting in a change in bid price. The final proposal includes a contractually agreed-upon price.

13. Q. **WHAT ARE THE MAIN REASONS FOR THE COST ESCALATION OF THE GREENLINK NEVADA TRANSMISSION PROJECT?**

A. Since the original estimates were created and following the COVID-19 pandemic, there have been significant disruptions to the international supply chain, a shortage in the available workforce, and a substantial rise in inflation. The cost of raw materials used in the manufacturing of electrical equipment (e.g., steel, aluminum), transportation, and fuel has increased significantly since 2020. These increases have led to an overall increase in the cost of materials needed for the construction of the Greenlink Nevada transmission project. The workforce shortage and inflated prices have caused a significant increase in labor costs, resulting in a higher forecasted cost of construction for the Greenlink Nevada transmission project. As the Companies have received final proposals or have entered into contracts for long-lead-time materials, the final cost of these materials includes shipping of equipment and materials to the construction sites. These shipping costs were not known at the time of development of original estimates, as the location of providers was not known.

The forecast provided in this filing includes \$340.8 million in escalation from 2024 to 2028. The escalation represents contractual terms and costs for materials and services that are aligned with specific material indices and contractual labor rate increases for IBEW Local 396 and Local 1245. For this forecast, NV Energy assumed an increase of 3.5 percent per year in material indices. Inclusion of escalation in the project forecast provides the Commission with a better estimate of final project costs in the future.

The forecast includes \$101 million in sales and use taxes. These taxes were not included in the original forecast.

The forecast includes \$124 million associated with the cost of incremental 160 miles (62 percent) of H-Frame structures that are required by the Bureau of Land Management for Sage Grouse and Desert Tortoise habitat risk mitigation.

The forecast includes \$97.4 million for the construction of Fort Churchill–Comstock #2 345 kilovolt transmission line. The construction of this segment is being requested in this filing and is subject to approval by the Commission. The Commission had originally only approved \$12.8 million for the permitting and preliminary design and engineering of this transmission line. The costs of the unapproved element of the line (construction) are included in this forecast to provide the Commission with a comprehensive overall project forecast.

An additional \$30.7 million is included in this forecast to mitigate environmental risk as stipulated by the Bureau of Land Management.

Details of these increases in cost of materials and labor and additional items included in the project scope as discussed above are provided in **Exhibit Lateef-Direct-2 - Greenlink Forecast Update – May 2024**.

14. Q. WHAT ARE THE KEY STEPS THAT THE COMPANIES HAVE TAKEN TO CONTROL COSTS OF THE GREENLINK NEVADA TRANSMISSION?

1 A. The Companies have sought competitive bids from multiple providers for all
2 materials and services required for the Greenlink Nevada transmission project. In
3 all cases, the Companies have selected the lowest cost technically qualified bidder
4 to provide materials and services.

5
6 The Companies have procured the services of an independent organization to
7 provide an ongoing review of its engineering and design specifications to ensure
8 that the specifications for materials and services are based on Companies' standards
9 and are in line with industry practices.

10
11 The Companies have adjusted its project overhead, administrative, and general
12 accounting rates to make those in-line with similar past large transmission projects.
13 The overhead, administrative and general accounting rates for Greenlink Nevada
14 transmission project are based on ON Line, 525 kilovolt transmission line between
15 Robinson Summit and Harry Allen substations, that was placed in-service in 2013.
16 ON Line accounting was subject to a successful Federal Energy Regulation
17 Commission review, with no concerns identified. These adjustments have resulted
18 in significantly lower overhead, administrative and general accounting charges
19 being applied to the Greenlink Nevada transmission project.

20
21 To achieve lowest possible cost of construction of transmission line, substations,
22 and telecommunications infrastructure, the Companies have requested and received
23 proposals for combined construction of these facilities by the same contractor. The
24 Companies are currently reviewing the combined construction proposals from two
25 technically qualified bidders.

15. Q. **WHAT IS THE CURRENT STATE OF THE BLM PERMITTING FOR GREENLINK NEVADA TRANSMISSION?**

A. The BLM published its Draft Environmental Impact Statement for Greenlink West and the Common Ties on May 26, 2023. A 90-day public comment period started on May 26, 2023. The BLM conducted public meetings on the Greenlink West draft Environmental Impact Statement in July 2023. The BLM plans to publish the Final Environmental Impact Statement for Greenlink West in June 2024, followed by a Record of Decision in August 2024 and a Notice to Proceed in December 2024.

The BLM published the Notice of Intent to develop Environmental Impact Statement for Greenlink North on May 26, 2023, and held public scoping meetings in June 2023. A Draft Environmental Impact Statement for Greenlink North is planned to be issued in July 2024, followed by a Final Environmental Impact Statement in April 2025, a Record of Decision in June 2025, and a Notice to Proceed in December 2025.

16. Q. **ARE THERE OTHER RISKS FOR FUTURE CHANGES TO THE COSTS ASSOCIATED WITH THE GREENLINK NEVADA TRANSMISSION PROJECT?**

A. Yes. The BLM permitting process can have significant impact to the overall cost of the Greenlink Nevada Transmission project.

A significant change to the estimated increase of 3.5 percent per year in indices associated with the commodity markets, labor markets, transportation, or fuel costs may also result in increase or decrease to the overall cost of the Greenlink Nevada Transmission project.

17. Q. **HOW CAN THE NATIONAL ENVIRONMENTAL POLICY ACT (“NEPA”) PERMITTING PROCESS CHANGE THE OVERALL COSTS OF GREENLINK NEVADA TRANSMISSION?**

A. A preferred transmission line route or the exact location of substations has not been finalized pending development of the Final Environmental Impact Statement for Greenlink West, Common Ties and Greenlink North. The Nevada state office of the BLM is the lead agency for the Greenlink NEPA process. The BLM, in coordination with other federal agencies, tribes, counties, cities and other cooperating agencies, is currently considering several alternatives that can change the length, location and/or design of the transmission lines and collector substations. The Final Environmental Impact Statement will also stipulate detailed environmental mitigation measures, which can impact the overall cost of the project. As an example, the BLM is requiring the Companies to use “H-Frame” structures in expanded Desert Tortoise and Sage Grouse habitats. The per-mile cost of “H-Frame” structures is 42 percent higher compared to “Guyed V Lattice” structures planned for the transmission lines. The difference in cost of the two types of structures is based on higher weight and cost of steel needed for the “H Frame” structures and shorter transmission line span lengths associated with the “H-Frame” structures resulting in a larger quantity of structures needed.

Any permitting delays on behalf of the BLM may result in compression of construction schedule to meet the intended in-service dates for the Greenlink Nevada transmission project. A compression in schedule may result in an increase in construction costs.

Any permitting delays on behalf of the BLM may also result in long-lead-time materials arriving prior to the start of construction, requiring additional logistics, storage, and material management costs.

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

A. Yes.

EXHIBIT LATEEF-DIRECT-1

STATEMENT OF QUALIFICATIONS

Shahzad M. Lateef
Senior Project Director – Greenlink Nevada Transmission
NV Energy
6226 West Sahara
Las Vegas, Nevada 89146
(702) 402-6652

My name is Shahzad M. Lateef. My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am the Senior Project Director for Greenlink Nevada Transmission Project being developed by Nevada Power Company and Sierra Pacific Power Company.

I graduated from the University of Nevada – Las Vegas in May of 1994 with a Bachelor of Science degree in Electrical Engineering. I received a Master of Science Degree in Electrical Engineering from University of Nevada – Las Vegas in December of 1997.

In March of 1995, I joined the Nevada Power Company as an associate Engineer with Bulk Power Operations. In this role, my primary activities were to analyze unit commitment for Nevada Power Company's generation fleet, and nominate natural gas needed for the generation plants.

In January of 1997, I transferred to Distribution Planning as an engineer. This role involved distribution facility loading assessment, and planning and design for capital projects to support the load growth.

In January of 1998, I accepted the position of senior engineer with Resource Planning department. Within this role, I was responsible for the support of Nevada Power Company's resource plans utilizing various short-term and long-term production cost models. I also performed mid to long term power contract evaluations as a part of this role.

In March of 1999, I transferred to Distribution Operations as a senior engineer. In this role, I was responsible for resolution of power quality issues across Nevada Power Company service region. I also provided support to distribution system operations and real-time dispatch services.

In November of 2005, I was selected as Supervisor for Transmission and Distribution Operations for Nevada Power Company. In this role, I was responsible for real time operation of Nevada Power Company's transmission and distribution systems. The role also included oversight of operational engineering function.

In December of 2008, my role within Transmission and Distribution System Operations was expanded to include the Distribution Operations Technology, Electric Dispatch, and Gas dispatch for Sierra Pacific Power Company. My title with this expanded role was changed to Manager, Transmission and Distribution System Operations.

In October of 2013, I was transferred to the role of Manager of Distribution Operations. In this role, I had the responsibility of overseeing Distribution System Operations for Nevada Power Company and Sierra Pacific Power Company, Trouble Dispatch for electric and gas dispatch at both companies, Distribution Operations Technology, and Operations Engineering.

In May of 2014, I accepted the position of the Director of Transmission and Distribution System. In this role, I was responsible for Balancing Authority, Transmission Operations, Distribution Operations, Electric Trouble Dispatch, Network and Operations Engineering for Nevada Power Company and Sierra Pacific Power Company.

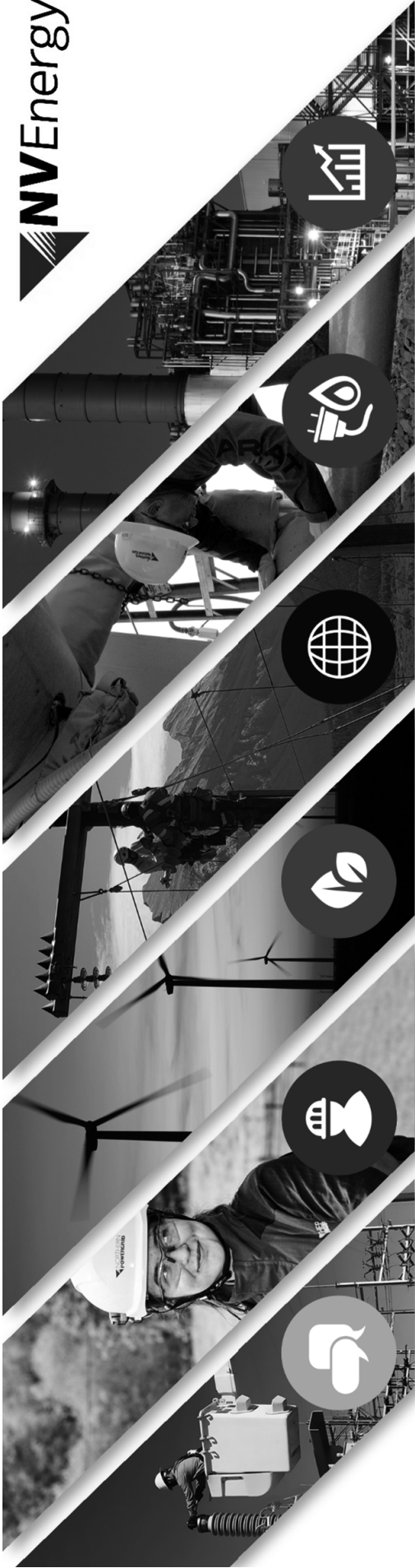
In October of 2017, I accepted the position of Vice President of Transmission. In this role, I had the responsibility for Balancing Authority Operations, Transmission Operations, Distribution Operations, Electric Trouble Dispatch, Transmission Planning, Substations Operations and Engineering, Transmission Policy, and Telecommunication Operations.

In May of 2020, I accepted the position of Vice President of Electric Delivery. In this role, I had the responsibility for safe and reliable operation of all of NV Energy's electric system. My area of responsibility included Transmission and Distribution Operations, Substations Operations, Metering Operations, Telecommunications Operations, New Business, Vegetation Management, and Fleet Operations.

In February of 2022, I accepted by current role as the Senior Project Director for the development of Greenlink Nevada Transmission Project. In this role, I have the overall responsibility for safe, compliant, and efficient development of all aspects of Greenlink Nevada Transmission Project.

I am a licensed profession engineer in the State of Nevada.

EXHIBIT LATEEF-DIRECT-2



Greenlink Nevada Transmission

Forecast Update

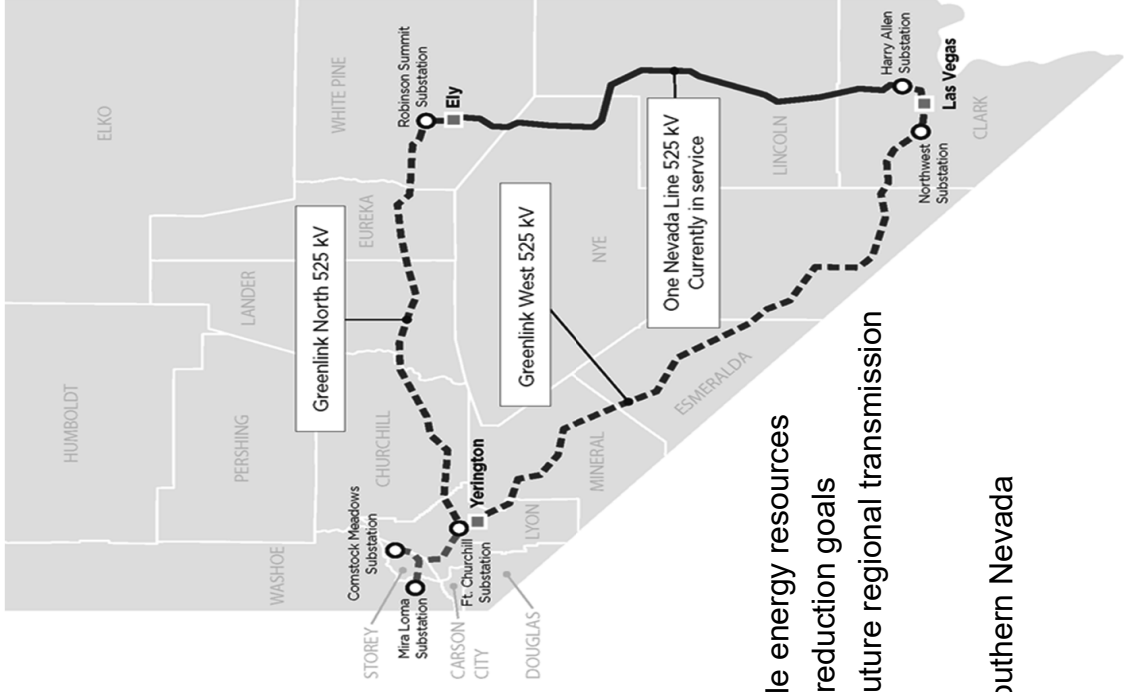
2024 Integrated Resource Plan

May 2024

Greenlink Nevada Transmission Project



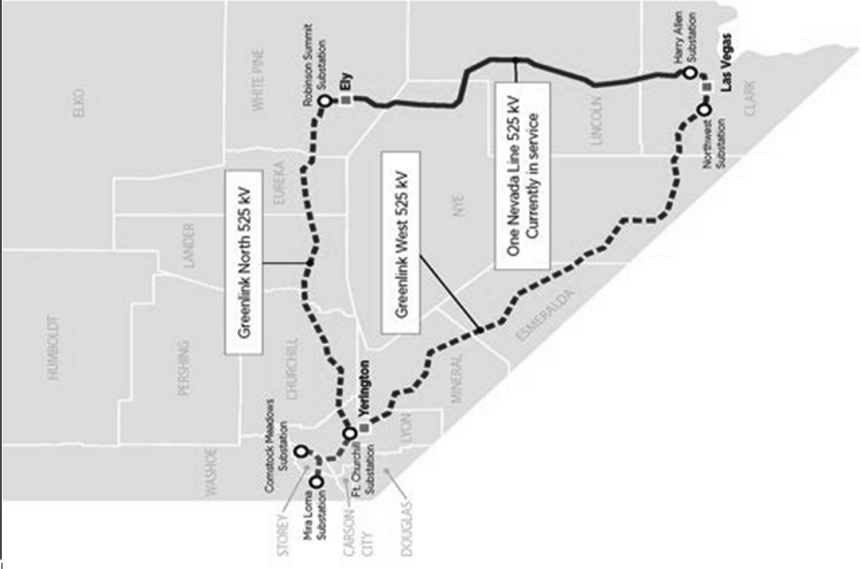
- **Greenlink West**
 - Fort Churchill to Northwest 525 kV
 - Northwest to Harry Allen 525 kV
 - Northwest substation expansion
 - Amargosa and Esmeralda 525/230 kV collector substations
- **Greenlink North**
 - Fort Churchill to Robinson Summit 525 kV
 - Lander 525/230 kV collector substation
- **Common Ties**
 - Fort Churchill 525-345-230-120 kV substation
 - Fort Churchill to Mira Loma 345 kV
 - Fort Churchill to Comstock Meadows #1 345 kV
 - Fort Churchill to Comstock Meadows #2 345 kV
- **Benefits for customers and the state of Nevada**
 - Creates access to new areas of the state to develop affordable renewable energy resources
 - Facilitates ability to meet Nevada's renewable development and carbon-reduction goals
 - Positions Nevada to benefit from renewable energy resource mix when future regional transmission projects interconnect at Robinson Summit
 - Strengthens electric reliability for Nevada
 - Aligns with long-term statewide economic growth both in northern and southern Nevada
 - Positions Nevada as energy leader in western U.S.



Greenlink Nevada Transmission



Milestone	Status	
	Greenlink West	Greenlink North
Engineering design	60% to 90%	10% to 30%
Conductor, control cable, control enclosures, disconnect switches, fixed series capacitors, microwave towers, neutral reactors, shunt reactors, shield wire, transformers, tubular poles, and shield wire	Contract	Contract
Transmission line arresters, transmission line construction, and lattice towers	Recommendation for award	Recommendation for award
Insulators, optical ground wire, substation construction, and telecommunication construction	Contract negotiation	Contract negotiation
BLM Draft Environmental Impact Statement	Complete	July 2024
BLM Final Environmental Impact Statement	June 2024	April 2025
BLM Record of Decision	August 2024	June 2025
BLM Notice to Proceed	December 2024	December 2025
In-Service	May 2027	December 2028



Project (Includes contingency, escalation & AFUDC)		Length	Voltage	In-Service
Greenlink West (Fort Churchill substation to Northwest substation)		326 miles	525 kV	5/31/2027
Greenlink West (Harry Allen substation to Northwest substation)		33 miles	525 kV	12/31/2028
Common Ties		81 miles	345 kV	5/31/2027
Greenlink North		234 miles	525 kV	12/31/2028

Project Budget Summary

Includes Contingency and Escalation, Excludes AFUDC



	Docket 20 07023 (2019 \$)	Docket 21 06001 & DR # 232 (2020 \$)	June 2023 PUCN Forecast Update 5 th Amendment 2021 IRP (2023 \$)	May 2024 Forecast (Includes escalation through end of the project segments)
Harry Allen – Northwest 525kV	\$ 14.3m	\$ 143.1m	\$ 155.5m	\$ 199.4m
Northwest – Walker River 525kV	\$ 1,036.9m	\$ 989.5m	\$ 1,154.6m	\$ 1,595.6m
Northwest Substation	\$ 80m	\$87.3m (Prior approval)	\$ 105m	\$ 111.9m
Greenlink West Total	\$ 1,116.9m	\$1,220m	\$ 1,415.1m	\$ 1,906.9m
Robinson Summit – Fort Churchill 525kV	\$26.4m	\$ 854.1m	\$ 1,050.6m	\$ 1,490.3m
Greenlink North Total	\$ 26.4m	\$ 854.1m	\$ 1050.6m	\$ 1,490.3m
Fort Churchill Substation Expansion	\$ 199.8m	\$ 246.6m	\$ 281.3m	\$ 448.2m
Fort Churchill – Mira Loma 345kV	\$ 85.2m	\$ 83.4m	\$ 96.3m	\$ 152.5m
Fort Churchill – Comstock Meadows #1 345kV	\$ 67.9m	\$ 67.2m	\$ 8.8m	\$ 130.5m
Fort Churchill – Comstock Meadows #2 345kV	\$ 12.8m	\$ 12.8m (Prior approval)	\$ 75.1m	\$ 110.2m
Common Ties Total	\$ 365.7m	\$ 410m	\$ 461.5m	\$ 841.4m
Greenlink Nevada Total	\$ 1,509m	\$ 2,484m	\$ 2,927m	\$ 4,238.6m

Project Budget Detailed Summary

Base Costs, Contingency, & Escalation



	Base Costs (2023 \$)	Contingency Risk based (2023 \$)	Escalation	Total
Harry Allen – Northwest 525kV	\$ 166.2m	\$ 15m	\$ 18.3m	\$ 199.4m
Northwest – Walker River 525kV	\$ 1,366.3m	\$ 122.9m	\$ 106.3m	\$ 1,595.6m
Northwest Substation	\$ 96.8m	\$ 8.7m	\$ 6.4m	\$ 111.9m
Greenlink West Total	\$ 1,629.3m	\$ 146.6m	\$ 131.0m	\$ 1,906.9m
Robinson Summit – Fort Churchill 525kV	\$ 1,152.0m	\$ 184.3m	\$ 154.0m	\$ 1,490.3m
Greenlink North Total	\$ 1,152.0m	\$ 184.3m	\$ 154.0m	\$ 1,490.3m
Fort Churchill Substation Expansion	\$ 386.1m	\$ 34.7m	\$ 27.3m	\$ 448.2m
Fort Churchill – Mira Loma 345kV	\$ 123.1m	\$ 19.7m	\$ 9.7m	\$ 152.5m
Fort Churchill – Comstock Meadows #1 345kV	\$ 102.7m	\$ 16.4m	\$ 11.4m	\$ 130.5m
Fort Churchill – Comstock Meadows #2 345kV	\$ 88.6m	\$ 14.2m	\$ 7.4m	\$ 110.2m
Common Ties Total	\$ 700.5m	\$ 85.1m	\$ 55.8m	\$ 841.4m
Greenlink Nevada Total	\$ 3,481.8m	\$ 416.0m	\$ 340.8m	\$ 4,238.6m

Greenlink Nevada



Contracts and Proposals Received for Materials, Services and Taxes

Material/Service	Comments
Comprehensive Project Services – Owners Engineer	Contract in place
Transmission Line Construction	Best and Final Proposals Received. Contract Negotiations in progress
Substation Construction	Best and Final Proposals Received. Contract Negotiations in progress
Substation Shaped Steel and Insulators	Proposals received. Negotiations in progress with low-cost provider
Telecom Construction	Best and Final Proposals Received. Contract Negotiations in progress
Fixed Series Capacitors	Contract in place
Power Transformers and Shunt Reactors	Contract in place
Circuit Breakers	Contract in place
Substation and Transmission Tubular Steel Pole Structures	Proposals received. Negotiations in progress with low-cost provider
Lattice Steel Structures	Proposals received. Negotiations in progress with low-cost provider
Instrument Transformers and Neutral Reactors	Contract in place
Disconnect Switches	Contract in place
Conductor and Shield Wire	Contract in place
Control Enclosures and Panels	Contract in place
OPGW	Proposals received. Negotiations in progress with low-cost provider
Microwave Towers	Proposals received. Negotiations in progress with low-cost provider
Sales and Use Tax	Estimated sales and use taxes on material
Shipping	Estimated shipping and demurrage costs on material
Environmental Permitting	Contract in place

Key Reasons for Cost Escalation



- Original estimates prepared in 2019 pre-COVID, based upon preliminary studies and no design
- Inflation in 2020 – 2023 highest in 40 years. Producer Price Index increased 30% (\$771m)
- BLM requirements:
 - Estimates assumed 258 miles of 525kV H-Frame structures based upon prior BLM permits
 - BLM required H-Frame structures in desert tortoise and sage grouse habitats, adding 160 (62%) more miles
 - Installed cost of H-frame structures is 42% higher (per mile) than lattice structures, due to shorter span lengths, more structures, and heavier structures (\$153m incremental costs)

- Significantly higher costs and longer lead-times from 2020-Q1 to 2023-Q3

COMMODITY	Cost Increase	Lead Time Increase
BREAKERS	128%	413%
CABLE	68%	98%
POWER TRANSFORMERS	69%	113%
SWITCHGEAR	54%	141%

Key Reasons for Cost Escalation (cont.)



- High demand for labor
 - Transmission line construction
 - 26 bidders invited
 - 3 bidders provided proposals and were technically qualified
 - Best and Final proposals received from two contractors. Contract negotiations underway
 - Substation construction
 - 29 bidders invited
 - 2 bidders provided proposals and were technically qualified
 - Best and Final proposals received from two contractors. Contract negotiations underway
 - Telecommunications construction
 - 36 bidders invited
 - Best and Final proposals received from two contractors. Contract negotiations underway
 - Combined construction of transmission line, substation and telecommunications
 - Best and Final proposals received from two contractors. Contract negotiations underway
- Bidders seeking to mitigate risk of material and labor by increasing bid
 - NV Energy is requiring use of “Economic Price Adjustments” based on specific indices in its contracts

Key Risks to Current Forecast



- **Greenlink West scope and schedule are subject change pending BLM Record of Decision**
 - H-Frame structure quantities subject to finalization of desert tortoise and sage grouse habitats. Draft EIS has identified requirements for H-Frame structures. NV Energy is meeting with BLM and contractors regularly to identify significant changes from the draft EIS. Final EIS is expected in May 2024, ahead of PUCN order on the 2024 IRP
 - Local jurisdiction permitting and easement acquisition are underway and subject to change. NV Energy team is meeting with local jurisdictions, planning and advisory boards to understand and mitigate any concerns. E.g. road maintenance agreements, dust mitigation etc.
 - Environmental mitigation measures are subject to change. NV Energy is meeting with BLM and contractors regularly to identify significant changes from the draft EIS. Final EIS is expected in May 2024
 - Most recent BLM published schedule targets issuing the record of decision by June 2024. NV Energy is meeting with BLM and contractors regularly to identify significant changes from the draft EIS. Final EIS is expected in June 2024, on schedule for August 2024 record of decision
- **Greenlink North scope and schedule are subject to change pending BLM Record of Decision**
 - Notice of intent published in June 2023
 - Stakeholders proposed alternative routes that are 124 and 273 miles longer than proposed route. Information provided to BLM to assist in determining if the alternatives should be carried forward. BLM is not carrying forward these alternatives
 - Final environmental mitigation measures are subject to change affecting construction scope of work. NV Energy is meeting with BLM and contractors regularly to identify potential issues and addressing those proactively
 - If final line route is significantly different than the preferred route and alternatives being carried forward, NV Energy will seek re-approval of the project from the PUCN, as other alternatives may become more viable due to increased line length
- **New Initiatives (Included in the forecast)**
 - Accelerate construction of second Walker River – Comstock Meadows 345 kilovolt transmission line for major load additions. This line construction is being requested in 2024 IRP. PUCN had only approved permitting and design, which is progressing in 2024. Line construction is planned after PUCN order on 2024 IRP
 - Construction costs is estimated, and will be negotiated and agreed with the contractor upon receiving PUCN approval

Key Risks to Current Forecast



- **Economic Price Adjustments**

- Proposals for labor and material are tied to commodity indexes to mitigate risks
- NV Energy assumed a 3.5% escalation in major commodity indices to calculate escalation. Some of the indices have come down since contracts were signed. Any reduction in contract values based on indices increasing less than 3.5% will be realized in overall project costs
- IBEW contracts and associated wage rates for L396 and L1245 have been set for most of the construction phases of the project. IBEW wage increases are included in calculated escalation of contracts



NVEnergy

AFFIRMATION

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

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

Date: May 31, 2024

Shahzad Lateef
SHAHZAD M. LATEEF

JOHN TSOUKALIS

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 ____

Prepared Direct Testimony of

John Tsoukalis

I. Introduction and Qualifications

1. **Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.**

A. My name is John Tsoukalis. I am a Principal at The Brattle Group. My business address is 1800 M Street NW, Suite 700N, Washington, DC 20036.

2. **Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?**

A. I am submitting this direct testimony before the Nevada Public Utilities Commission (“PUCN” or the “Commission”) on behalf of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (together, “NV Energy” or the “Companies”).

3. **Q. PLEASE DESCRIBE THE BRATTLE GROUP.**

A. The Brattle Group is a consulting firm with a professional staff in excess of 400 individuals and offices in North America, Europe, and the Asia-Pacific region. The firm was founded in 1990 in Cambridge, Massachusetts. We have a large electric power practice focused on market, regulatory, and financial matters in the industry. We are an industry leader and provide planning support as well as expert testimony

on electricity rate design, transmission system expansion and coordination, analysis of the benefits and risks of investments or ownership of electricity assets and contracts, and analysis of wholesale electricity markets. We also advise clients on the design, pricing, and risk management of wholesale and retail services, and provide testimony on these matters before regulatory agencies for electric utilities and other market participants.

4. Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I am an energy economist and regulatory expert with an educational background in economics and over 10 years of experience advising clients in the electric power industry. For multiple clients, I have assessed the benefits, costs, and operational impacts of participation in regional wholesale markets in the western U.S. and in the southeastern U.S. I have analyzed and modeled the power system in various parts of North America, advised clients on market entry decisions, regulatory and policy matters, market design, transmission investment decisions, rate design, and compliance with market power rules. In addition, I have assisted clients in comprehensive organizational strategic planning efforts.

I have provided testimony before the Federal Energy Regulatory Commission (FERC) on several occasions, before the Alberta Utilities Commission, and before a U.S. District Court.

I hold a Bachelor of Arts in Economics from Washington and Lee University, a Master of Science in Economics from The Barcelona Graduate School of Economics, and a Master of Science in Economic Analysis from the Universitat

Autònoma de Barcelona. My statement of qualifications is attached as **Exhibit Tsoukalis – Direct 1 – Statement of Qualifications.**

5. Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.

A. In my testimony, I analyze the benefits of the Greenlink transmission projects (“Greenlink” or “the projects”)¹ for Nevada customers and assess the increase in costs for Greenlink compared to cost increases experienced by similar transmission projects across the industry.

6. Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY

A. I calculate several benefit metrics that capture the customer savings created by Greenlink. The metrics I calculate focus on the efficiency gains created by the projects, the impact on short-term transmission revenues collected by NV Energy, and the impact on congestion revenues collected by NV Energy through the Extended Day-Ahead Market (EDAM) and the Western Energy Imbalance Market (WEIM). I find that Greenlink:

- Reduces power costs for Nevada customers by \$57.3 million/year. Greenlink creates this customer savings by reducing the fuel and operating costs of NV Energy-owned or contracted resources by \$6.7 million/year, by reducing purchased power costs by \$11.9 million/year, and by increasing off-system sales revenues by \$38.7 million/year.
- The reduction in power costs for Nevada customers is offset by a reduction in short-term wheeling revenues collected by NV Energy of \$0.7 million/year, bilateral trading profits earned by NV Energy of \$1.1 million/year, and market

¹ The Projects include Greenlink North, Greenlink West, and the Common Ties projects. Greenlink North is a 525 kV transmission line connecting the Robinson Summit and Fort Churchill substations, through the Lander substation. Greenlink West is a 525 kV transmission line connecting the Fort Churchill and Harry Allen substations, through the Esmeralda, Amargosa, and Northwest substations. The Common Ties projects are two 345 kV transmission lines that connect the Fort Churchill substation to the Comstock Meadows and Mira Loma substations in the Reno area.

congestion revenues collected by NV Energy through the WEIM and EDAM of \$4.6 million/year. These revenues streams decline slightly due to Greenlink, because the projects have a profound impact on reducing congestion within the NV Energy system and in the region.

- In total the annual market benefit for NV Energy customers created by Greenlink is \$50.8 million/year. The net present value (NPV) of the annual customer savings over the life of the Greenlink projects is \$926.8 million.
- Provides economic benefits to the state of Nevada in the form of over 3,200 direct full time equivalent (FTE) jobs in the state, and over 6,800 total FTE jobs (direct and indirect). The projects will generation \$1,100 million/year in economic stimulus benefits in local Nevada communities.
- Defers or avoids potential future transmission upgrades or projects needed to maintain system reliability. Greenlink is likely to alleviate or eliminate reliability issues on the system that would materialize as load grows and system usage patterns change. The Greenlink projects will help accommodate system changes and potentially defer or reduce the need for future upgrades on the system.
- Increases the resiliency of the NV Energy system by creating additional transfer capability between the NV Energy-South (NVE-S) and NV Energy-North (NVE-N) systems. Specifically, in the event of an outage on the One Nevada (ON) line, NV Energy loses the ability to transfer power between NVE-South and NVE-North without the Greenlink projects. As a result, Greenlink will significantly reduce the reliability and economic impact on customers of an outage on the ON line.
- Accommodates load growth and future transmission service requests.
- Increases the interconnection with neighboring entities in the region, which augments the customer benefits from NV Energy's participation in the Western

1 Resource Adequacy Program (WRAP), by potentially increasing the ability of
2 NV Energy to trade capacity with its neighbors through the WRAP depending
3 on the availability of resources and transmission. The increased interconnection
4 with neighboring entities also augments the benefits to customers of NV
5 Energy's membership in a potential future regional transmission organization
6 (RTO) in the Western Electricity Coordinating Council (WECC).

7
8 In addition to the market-related operational benefits created by Greenlink that I
9 calculate in my testimony, NV Energy witnesses Williams and Pottey find that the
10 projects will save customers' money in other ways. NV Energy witness Williams
11 finds that a resource portfolio including the Greenlink projects will cost customers
12 over \$830 million less over the next 26 years and deliver a higher level of reliability,
13 compared to a resource portfolio that does not include the projects.² As discussed
14 in the testimony of NV Energy witness Pottey, a large driver of the customer cost
15 savings derived from the Greenlink projects is due to the avoided generation
16 interconnection projects needed to integrate the clean energy generation resources
17 necessary to comply with Nevada's renewable portfolio standard (RPS) and keep
18 up with load growth, which would cost customer more than \$3 billion to build.³

19
20 The benefits quantified by the NV Energy witnesses and in my analysis do not
21 include additional customer benefits, such as the increased value of participation in
22 WRAP or a potential future RTO and the possibility of deferring or avoiding future
23 reliability upgrades due to Greenlink.

24
25 I analyze the cost increases experienced by Greenlink over the last four years,
26 controlling for changes in project scope, differences in contingency assumptions,

27 ² See Direct Testimony of Kimberly Williams.

³ See Direct Testimony of Charles Pottey.

and different applications of future project cost escalation and sales tax costs across the cost estimates in 2021 vs in 2024, and find that:

- The estimated cost of Greenlink has increased from roughly \$2.5 billion in 2021 to \$4.2 billion in 2024.⁴ However, a large share of that cost increase is due to changes in the project scope and the absence of certain types of costs in the 2021 estimate. An apples-to-apples comparison of the same cost categories for the same project scope reveals that costs increased roughly from \$2 billion in 2021 to \$3.1 billion in 2024, an increase of roughly 16 percent per year.
- This cost increase is lower than the average increase seen across the Bureau of Labor Statistics' Producer Price Index (PPIs) related to electric power infrastructure and wage growth indices, the average of which increased at a compound annual growth rate (CAGR) of approximately 17 percent per year between 2021 and 2024.

Therefore, the costs increase experienced on the Greenlink projects is slightly less than industry-wide inflation experienced over the last several years for similar transmission projects.

II. Customer Savings Analyzed and Analytical Approach

7. Q. PLEASE EXPLAIN THE DIFFERENT WAYS THAT GREENLINK CREATES SAVINGS FOR NV ENERGY CUSTOMERS.

- A. The Greenlink projects create significant benefits for power customers and residents in Nevada in several ways. The projects create new transfer capability between the northern and southern portions of NV Energy's service territory that allows for more efficient operation of the grid, a lower-cost resource plan, the interconnection of clean generation resources necessary to meet Nevada's RPS, and

⁴ See Direct Testimony of Shahzad Lateef.

1 reduced emissions. The development of new energy infrastructure in the state will
2 create new jobs, tax revenues, and economic stimulus benefits for residents and
3 taxpayers in Nevada.

4
5 I capture the myriad customer savings and economic benefits created by Greenlink
6 through various metrics calculated in my analysis:

- 7 • **Adjusted Production Cost (APC) Savings:** a metric that accounts for the
8 reduction in fuel and operating costs for NV Energy due to the ability to operate
9 its resources more efficiently with the Greenlink projects and the ability for the
10 EDAM to better optimize power purchases and sales for NV Energy with the
11 projects.
- 12 • **Short-Term Wheeling Revenues:** a metric that accounts for revenues received
13 by NV Energy through the sales of short-term transmission service for the use of
14 its transmission system by the third parties, and the impact on those revenues
15 due to Greenlink.
- 16 • **Market Congestion Revenues:** a metric that accounts for congestion revenues
17 within the NV Energy Balancing Authority (BA) and between NV Energy and
18 its neighbors that would accrue to NV Energy through participation in the
19 EDAM and WEIM, and the impact on those revenues due to Greenlink.
- 20 • **Environmental Benefits:** a metric that accounts for the reduction in CO₂
21 emissions within Nevada and the region more broadly that occur due to the more
22 efficient operation of NV Energy and regional generation resources due to the
23 Greenlink projects.
- 24 • **Economic Benefits:** a metric that accounts for the employment and economic
25 impact benefits that accrue to the state of Nevada during construction and
26 operation of the new transmission infrastructure in Nevada.

1 In addition to these customer savings and benefit metrics, there are other customer
2 benefits created by Greenlink that I do not quantify that I will discuss later in my
3 testimony. These include the likelihood that Greenlink allows NV Energy to avoid
4 or defer future transmission projects or upgrades needed to maintain reliability, the
5 ability of Greenlink to accommodate future load growth in Nevada, the added
6 resiliency benefit created by the projects, and how Greenlink will enhance the
7 benefits NV Energy customers will receive from the Companies' participation in
8 the WRAP and from a potential RTO in the WECC
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10 **8. Q. PLEASE EXPLAIN THE APPROACH AND TOOLS USED TO ANALYZE**
11 **THE CUSTOMER SAVINGS CREATED BY GREENLINK.**

12 A. I rely on a production cost simulation model, Power System Optimizer (PSO), to
13 simulate the operation of the power system in NV Energy's service territory and
14 the WECC with and without the Greenlink projects. The results of these simulations
15 are used to calculate most of the customer savings metrics I discuss in this
16 testimony, including APC, market congestion revenues collected by NV Energy,
17 and the environmental benefits created by Greenlink.
18

19 In addition, I rely on several recent analyses of the economic benefits created by
20 similar transmission infrastructure projects and use those results to calculate the
21 expected economic impacts of Greenlink for the state of Nevada.
22

23 **9. Q. PLEASE DESCRIBE THE PRODUCTION COST SIMULATION MODEL**
24 **USED TO ANALYZE THE CUSTOMER BENEFITS OF THE GREENLINK**
25 **PROJECTS.**

26 A. PSO, developed by Polaris Systems Optimization, Inc. and run in the Enelytix
27 modeling environment, is a state-of-the-art market and production cost modeling
28

tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to those used by ISOs/RTOs, and with advanced features for modeling bilateral trading and contract path limits as well as the unique features of energy and ancillary service market designs, such as the EDAM. The model developed for this study (the “Greenlink benefits model”) was based on the model developed for NV Energy and other joint market benefits study participants between the summer of 2023 and January 2024 to conduct several studies of the benefits and costs due to participating in the EDAM or Markets+ regional power markets, including the study conducted for NV Energy and presented to the PUCN on April 3, 2024.⁵ To analyze the benefits of the Greenlink, I focused on the “Middle View 1” scenario from the EDAM/Markets+ benefits study conducted for NV Energy. In that scenario, NV Energy is in EDAM along with PacifiCorp, the Balancing Authority of Northern California (BANC), the Sacramento Municipal Utility District (SMUD), Portland General Electric, Idaho Power, and the California Independent System Operator (CAISO). Most of the remainder of the WECC is assumed to be in Markets+ in that scenario. Among the five market scenarios simulated for the EDAM/Markets+ benefits study, this scenario most accurately reflects recent market participation announcements from other utilities in the WECC.⁶

The study year is 2032, which aims to reflect the first decade of markets operations, representing both an intermediate year in the near-future and a year with reasonably

⁵ See The Brattle Group, NV Energy Day-Ahead Market Benefits Studies: Comparative Benefits for NV Energy of Joining EDAM vs Markets+, April 3, 2024.

⁶ At the time of filing this testimony, PacifiCorp, BANC, LADWP, Idaho Power, and Portland General Electric have publicly stated that they intend to join the EDAM. See PacifiCorp, “PacifiCorp to build on success of real-time energy market innovation as first to sign on to new Western day-ahead market,” December 8, 2022; California ISO, EDAM gains more momentum at recent Las Vegas forum, September 7, 2023; LADWP, Regular Meeting, February 13, 2024; Portland General, “Portland General Electric announces intent to join CAISO EDAM regional energy market to benefit customers, environment,” News Release, March 21, 2024; and California ISO, “Idaho Power and Portland General Electric signal intent to join EDAM,” March 21, 2024.

high renewable penetration in the WECC, and thus tends to represent an “average” view of the benefits of the project over its life. The EDAM/Markets+ Benefits study model includes non-public transmission, load, resource, and contract path data from other joint market benefits study participants that allows us to capture NV Energy more accurately and WECC-wide operations and market outcomes, and the impact of the Greenlink on those outcomes.

10. Q. PLEASE EXPLAIN THE ASSUMPTIONS USED TO MODEL THE GREENLINK PROJECTS.

A. The Greenlink benefits model was developed in collaboration with NV Energy staff to reflect the latest available NV Energy load, resource, and transmission outlooks from the NV Energy Integrated Resource Plan (IRP) and transmission teams. I first worked with NV Energy during the course of the EDAM/Markets+ Benefits study to update load, resource, and transmission outlooks to align with the best available views as of fall 2023. As I began the analysis of Greenlink benefits in spring 2024, I conducted a second round of updates to align to the extent possible the NV Energy load, resource, and transmission outlooks in the Greenlink benefits model to those NV Energy has created for the 2024 Joint IRP update,

To capture the impacts of the Greenlink on system operations and costs in the Greenlink benefits model, I worked with the NV Energy transmission team to refine the assumptions used in the model for transfer capability between NV Energy and its neighbors, and between northern NV Energy (NVE-N) and southern NV Energy (NVE-S), as well as the impact of Greenlink on those transfer limits. I additionally worked with NV Energy staff to develop assumptions for Greenlink impacts on simultaneous import and export capabilities of the NVE-N and NVE-S systems.

Figure PF-1 and Figure PF-2 show our total transfer capability (TTC) assumptions with and without Greenlink for the NVE-N and NVE-S systems. As shown in Figure PF-1 and Figure PF-2, Greenlink principally increases TTC in three ways:

- 1) It increases the transfer capability between NVE-S and NVE-N by 2,169 MW from north to south and by 1,745 MW from south to north, from the current transfer capability of 900 MW from north to south and 600 MW from south to north. The current transfer capability between NVE-S and NVE-N is entirely due to the ON Line. Therefore, when the ON Line is on outage there is no transfer capability between NVE-S and NVE-N.
- 2) It increases the simultaneous import and export limits of NVE-S by 1,372 MW and 1,745 MW, respectively, and those of NVE-N by 2,525 in both directions. This will allow NVE-S and NVE-N to transfer additional power to neighboring entities to increase valuable off-system sales or purchases.
- 3) It allows NV Energy to access increased power transfers from Idaho Power (IPCO) and the PacifiCorp East (PACE) BA via the SWIP-N and Crosstie transmission lines through Robinson Summit. Without Greenlink, the increased transfer capability created by those projects to NV Energy would be restricted due to the limitations on its system to transfer power out of Robinson Summit to other parts of the NV Energy system. Greenlink increases the TTC between NVE-N and NVE-S through Robinson Summit, by the amounts stated above, which opens up the possibility to import or export significantly more power to IPCO or PACE via SWIP-N and Crosstie, respectively.

I use the Greenlink benefits model to simulate a scenario with Greenlink and the corresponding TTC values shown in Figure PF-1, and a scenario without Greenlink and the corresponding TTC values shown in Figure PF-2. I compare the results of

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these two scenarios to calculate several of the Customer benefits metrics described
in the following section of my testimony.

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///

FIGURE PF-1: NV ENERGY SYSTEM TRANSFER CAPABILITY WITH GREENLINK

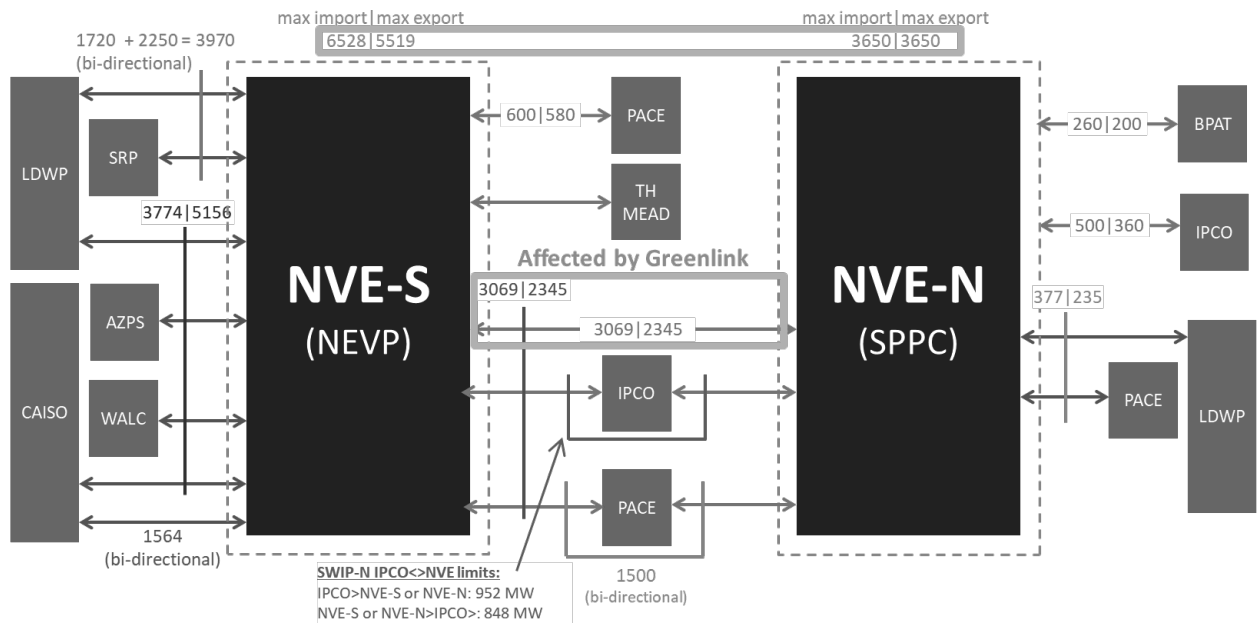
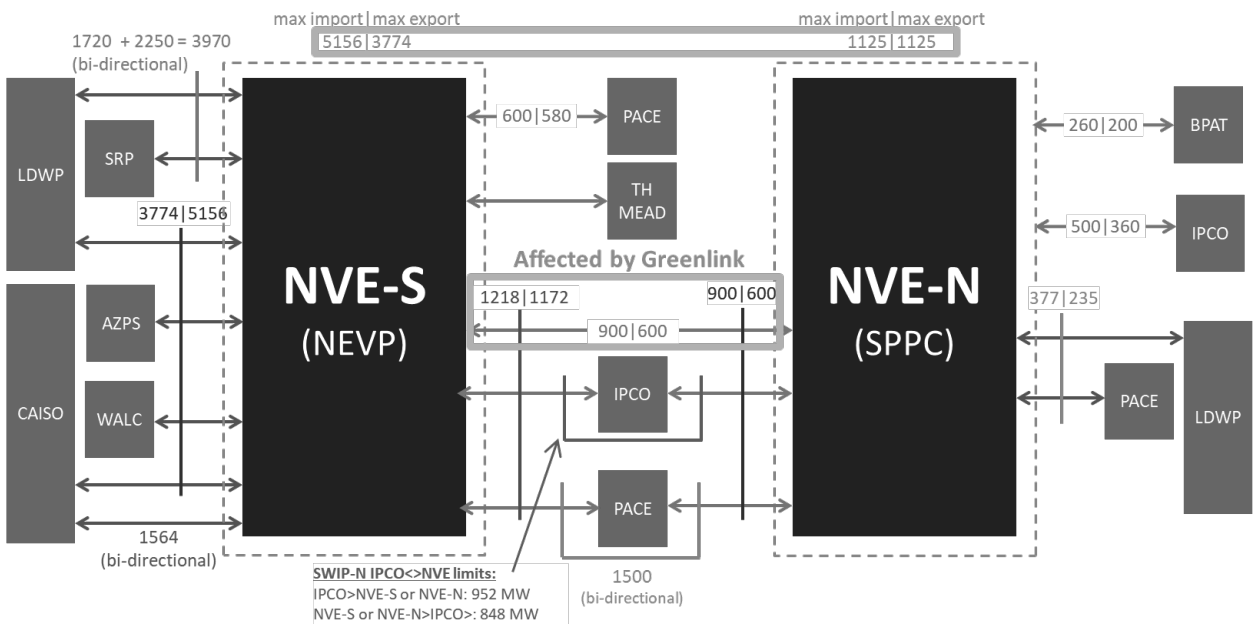


FIGURE PF-2: NV ENERGY SYSTEM TRANSFER CAPABILITY WITHOUT GREENLINK



III. Customer Benefits Created by Greenlink

11. Q. WHAT ARE THE TOTAL SAVINGS YOU CALCULATE CREATED BY GREENLINK FOR NEVADA CUSTOMERS?

A. I find that Greenlink creates \$50.8 million/year of customer savings. Figure PF-3 shows how each benefit metric contributes to the total customer savings I calculate. I review each component of Figure PF-3 individually below.

FIGURE PF-3: SUMMARY OF CUSTOMER SAVINGS

Benefit Metric	Metric	Row	Case Without Greenlink	Case With Greenlink	Greenlink Market Benefits
			\$ Millions	\$ Millions	\$ Millions
Adjusted Production Cost	Cost	[1]	\$698.2	\$641.0	\$57.3
Short-Term Wheeling Revenue	Revenue	[2]	\$14.0	\$13.3	-\$0.7
Bilateral Trading Revenue	Revenue	[3]	\$12.2	\$11.1	-\$1.1
WEIM Congestion Revenue	Revenue	[4]	\$20.6	\$19.5	-\$1.1
EDAM Congestion Revenue	Revenue	[5]	\$80.0	\$76.4	-\$3.5
					\$50.8

Notes:

[1] & [6]: As adjusted production cost and total system cost are costs, a decline is a benefit in the "Greenlink Market Benefit" column.

[2] - [5]: All revenue metrics show a benefit if the metric is increasing from the 'Without Greenlink' case to the 'With Greenlink' case.

12. Q. PLEASE EXPLAIN THE APC SAVINGS CREATED BY GREENLINK

A. The Greenlink projects create the ability to transfer more power across the NV Energy system and to import or export more power from neighboring systems. Therefore, the projects allow for a more efficient operation of NV Energy's owned or contracted resources, increasing operation of the lowest-cost resources and avoiding production from the highest-cost resources more frequently, leading to a reduction in fuel and operating costs for NV Energy customers. The increased ability to buy and sell power from neighboring entities adds to the efficiency gains created by Greenlink, allowing NV Energy to avoid fuel and operational costs when

power can be purchased at a low cost from neighbors and generating profits by selling power when it is economic to do so.

Figure PF-4 shows the detailed APC savings for NV Energy customers created by Greenlink. As shown in the table, the principal APC impact of developing Greenlink is a \$38.7 million increase in sales revenue, driven by a modest increase in sales as well as access to higher sales prices. Greenlink also increases NV Energy purchases from neighboring systems while at the same time reducing purchase prices through increased transfer capability and lower congestion with neighbors, resulting in an additional \$11.9 million per year reduction in NV Energy APC. Finally, Greenlink creates a \$6.7 million per year decrease in NV Energy resource production costs, representing the dispatch efficiency gain created by the project. In total, the Greenlink reduces NV Energy customer APC by \$57.3 million per year.

FIGURE PF-4: APC SAVINGS FOR NV CUSTOMERS CREATED BY GREENLINK

Cost Components		GWh			\$/MWh			Total (\$1000s/Year)		
		Without Greenlink	With Greenlink	Difference	Without Greenlink	With Greenlink	Difference	Without Greenlink	With Greenlink	Difference
Production Cost	(+) [1]	51,210	51,015	-195	\$14.51	\$14.43	-\$0.08	742,933	736,252	-\$6,681
Purchases Cost	(+) [3]									
Day-Ahead Market + Bilateral	[4]	6,463	6,792	329	\$23.50	\$20.71	-\$2.79	151,862	140,659	-\$11,203
Real-Time Market	[5]	1,919	1,962	44	\$19.37	\$18.60	-\$0.77	37,162	36,508	-\$654
Sales Revenue (Negative = Cost)	(-) [6]									
Day-Ahead Market + Bilateral	[7]	6,852	7,006	154	\$27.45	\$32.66	\$5.21	188,094	228,816	\$40,721
Real-Time Market	[8]	1,947	1,970	23	\$23.43	\$22.14	-\$1.29	45,618	43,618	-\$2,000
Total Cost (Negative Difference = Benefit)	[9]	50,793	50,793	0	\$13.75	\$12.62	-\$1.13	698,244	640,985	-\$57,259
% Change in APC										-8.2%

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs. A positive \$ amount in sales is a benefit to the entity, while a positive in purchases is a cost. Curtailment cost/PTC value only shows the change in cost of curtailments are a price of \$30/MWh for a curtailment.

13. Q. PLEASE EXPLAIN THE CHANGE IN REVENUES FOR NV ENERGY DUE TO GREENLINK.

A. I find that Greenlink causes a slight decrease in the short-term wheeling revenues NV Energy earns, the profits NV Energy earns from bilateral trading, and in the congestion revenues NV Energy collects from the EDAM and WEIM. In total these three metrics decline by \$5.6 million/year. I find that Greenlink reduces market

revenues related to congestion and bilateral transaction because the projects are effective at reducing congestion inside the NV Energy system and between NV Energy and its neighbors in the market. Greenlink increases the volume of economic energy transactions for NV Energy in the market, which is the largest driver for reducing power costs, but the projects simultaneously reduce overall congestion on the system and NV Energy's allocation of congestion revenues. Overall the operational and market benefits for NV Energy customers are positive by over \$50 million/year.

14. Q. PLEASE DESCRIBE THE ECONOMIC BENEFITS FOR NEVADA CREATED BY GREENLINK.

A. I find that Greenlink will support over 6,800 jobs and create over \$1 billion of economic activity in the local community. Large infrastructure projects like Greenlink create economic benefits for the communities in which they are located by supporting jobs, stimulating economic activity, and generating tax revenues for state and local governments. I calculate the likely jobs supported by Greenlink and the dollar of economic stimulus created by the project. I do not calculate the tax revenues paid by the project to state and local governments.

I reviewed several previous studies of the job and economic stimulus benefits of large transmission infrastructure projects from the last 15 years, including the study conducted by NV Energy in 2021 to determine the job and economic stimulus impact of the Greenlink projects. The results of these studies are summarized in Figure PF-5. Each looks at three metrics. First, the direct jobs supported by the transmission project during construction and throughout the life of the project. Second, the total jobs, which includes indirect jobs supported in the local economy due to the investment in the transmission project. For example, a share of the wages

paid to construction workers are spent on food and lodging during the development of the project, which supports local businesses and jobs in the community. Third, the economic output or stimulus created by the investment in the transmission project. For example, the transmission developer will purchase some share of materials from local suppliers, which will increase revenues and profits for those businesses that flow through to their suppliers, employees, and owners, who will spend a share of that in other sectors of the economy.

Figure PF-5 shows that the recent studies I reviewed found that direct full-time employees (FTEs) supported by large transmission projects range from 3.16 to 4.25 for every \$1 million of investment, for an average of 3.7. The total FTEs supported by large transmission projects range from 4.3 to 12.5 per \$1 million of investment, with an average of 7.69. This implies that every \$1 million invested in transmission infrastructure supports approximately 7.69 FTEs. The studies found a range of economic stimulus ranging from \$900,000 to \$2.92 million created for every \$1 million invested in transmission infrastructure, with an average of \$1.23 million (our average value excludes U.S.-wide estimates). These results align with NV Energy's own analysis from 2021 that found the Greenlink project would support 8.26 FTEs and create \$1.44 million of economic output per \$1 million of investment in the projects.

**FIGURE PF-5: SUMMARY OF GREENLINK JOB AND
ECONOMIC STIMULUS BENEFITS**

Study	Region	FTE Jobs & Output per \$1 MM Tx Investment		
		Direct FTE (#)	Total FTE (#)	Output (\$ MM)
2010 Brattle SPP	[1] SPP	3.9	4.3	\$0.90
2011 NREL	[2] Wyoming		4.8	
2011 Brattle WIRES	[3] US	4.25	12.5	\$2.92
2014 Brattle Nebraska Study	[4] Nebraska	3.96	6.6	\$1.10
	SPP	3.46	7.7	\$1.35
2021 London Economics International WIRES	[5] WECC	3.63	8.3	\$1.38
	US	3.16	9.5	\$1.52
2021 Applied Analysis NV Energy Report	[6] Nevada	3.56	7.8	\$1.44
Average for Greenlink Estimate	[7]	3.7	7.69	1.23
Greenlink 2024 Total Investment (\$ million)	[8]	3,823		
Share of investment to Nevada	[9]	23%		
2024 Nevada investment	[10] = [8]*[9].	890		
FTE & Output Estimate	[11] = [7]*[10].	3,297	6,852	1,099

I apply the averages presented in Figure PF-5 for all three metrics to the estimated cost of the Greenlink projects. The total estimated cost of Greenlink is approximately \$4.2 billion, however a portion of that is for contingency. I remove that portion of the cost estimate when I apply the average of each metric to the Greenlink project. Therefore, I am only accounting for the investment in materials and labor (including escalation), which totals about \$3.8 billion. With this approach I am conservative in my estimate of jobs and economic stimulus benefits from Greenlink. Specifically, if contingency funds are ultimately needed to develop the project my estimate of jobs supported and economic stimulus created by the project is understated.

Applying the average of the three metrics shown in Figure PF-5, I find that Greenlink will directly support over 3,200 jobs, over 6,800 total jobs, and create just about \$1.1 billion in economic activity in the local community.

15. Q. ARE THERE ADDITIONAL CUSTOMER SAVINGS AND BENEFITS
CREATED BY THE GREENLINK PROJECTS THAT YOU DO NOT
QUANTIFY IN YOUR ANALYSIS?

A. Yes. The NV Energy witnesses Williams and Pottey analyze the investment cost savings for customers, including the avoided generation interconnection costs created by Greenlink. NV Energy witness Williams analyzes the resource portfolio NV Energy would need to develop if Greenlink does not get built. Greenlink allows NV Energy to plan to a lower reserve margin and locate resources more efficiently while maintaining a reliable resource mix. NV Energy witness Williams finds that the resource plan including Greenlink results in over \$830 million of customer savings compared to the resource plan without Greenlink.⁷

NV Energy witness Pottey demonstrates that, in the absence of Greenlink, NV Energy will need to build substantial transmission lines, including several components of the Greenlink projects, to interconnect and accommodate the renewable energy resources necessary to meet NV's RPS. These necessary generation interconnection projects would cost NV Energy customers over \$3 billion,⁸ which would be avoided entirely with the development of Greenlink. This benefit covers nearly 75 percent of the Greenlink projects.

16. Q. ARE THERE ADDITIONAL CUSTOMER SAVINGS AND BENEFITS
CREATED BY GREENLINK THAT HAVE NOT BEEN QUANTIFIED?

A. Yes. The Greenlink projects will provide several additional customer benefits that neither the NV Energy witnesses nor I have quantified. These include, but are not limited to, potentially avoiding or deferring future investments needed to maintain

⁷ See Direct Testimony of Kimberly Williams.

⁸ See Direct Testimony of Charles Pottey.

reliability on the NV Energy system, accommodating future load growth in Nevada, adding redundancy to the grid and resiliency for Nevada customers, augmenting the benefits of NV Energy's participation in the WRAP and a potential future RTO.

17. Q. **PLEASE DESCRIBE THE OTHER BENEFITS CREATED BY GREENLINK THAT HAVE NOT BEEN QUANTIFIED.**

A. There are several additional benefits customers can expect from the Greenlink projects that neither the NV Energy witnesses nor I have quantified:

- **Avoided or deferred future reliability investments:** as load grows and the system evolves in other ways, NV Energy will find it necessary to invest in new transmission infrastructure or upgrade existing assets to maintain reliable operation of their system. With Greenlink in-service those future needs will likely be delayed, smaller in scope, or avoided all together due to the additional transfer capability and flexibility provided by Greenlink.
- **Redundancy and resiliency:** adding new transmission infrastructure creates additional paths and capacity to transfer paths across the grid, which helps reduce the cost of supplying power during outages on the system, and helps the system avoid service disruptions and return service to customers faster when interruptions have occurred due to outages. In the case of Greenlink, the project creates a redundant transfer path between NVE-N and NVE-S, which today can only be achieved over the ON Line. If the ON Line is out of service temporarily, NVE-N and NVE-S are isolated from each other. This will create higher-cost outcomes for NV Energy customers but may also create service interruptions depending on other factors on the system. Greenlink provides an alternative path between NVE-N and NVE-S, significantly reducing the possibility of service disruptions due to an outage on ON Line. The simulation model I use to calculate

several of the benefit metrics accounts for an outage on the ON Line. Therefore, the cost benefit of redundancy created by Greenlink is accounted for in my analysis. However, the reliability and resiliency benefit of that redundancy is not quantified nor captured in my analysis.

- **Capacity to accommodate load growth:** Greenlink creates additional headroom on NV Energy's system, which will allow it to accommodate some load growth without new transmission infrastructure or upgrades or reduce the cost of integrating new load in the future. See the testimony of NV Energy witness Maxfield for a description of all the load growth and transmission service requests accommodated by the Greenlink projects.
- **Augment the benefits of participating in the WRAP:** Greenlink increases the transfer capability between NVE-S and NVE-N and increases the simultaneous import and export capabilities of both parts of the NV Energy system with neighboring utilities. Therefore, Greenlink creates the possibility for NV Energy to trade more capacity through the WRAP with neighboring entities when it would be economic to do so and when the necessary transmission capacity is available. Given NV Energy's physical position within the WRAP footprint, Greenlink will create the possibility for NV Energy to sell more transmission service to utilities looking to buy or sell capacity through the WRAP, if transmission capacity is available to execute those transactions.
- **Increase in the benefits of a potential future RTO:** the savings for NV Energy customers created by participating in a potential future RTO will depend largely on how well interconnected NV Energy's system is with other members in the RTO. As I discussed previously, Greenlink increases the simultaneous import and export limits for the entire NV Energy system, which will allow a potential future RTO to increase trading between NV Energy and its neighbors. In a full

RTO market, this would include buying or selling reserves across the market footprint as well as energy. An RTO would include a consolidated balancing area, economic procurement of all operating reserve types, a common reserve requirement across the RTO, and a single resource adequacy requirement for the RTO. The increased transfer capability between NV Energy and other market members created by Greenlink will help reduce the reserves needed to maintain reliability, reduce the cost of procuring them in the market, and reduce the planning reserve margin necessary to maintain reliability in the RTO. Each of these impacts would reduce costs for customers in the RTO.

IV. Analysis of Greenlink Costs

18. Q. PLEASE DESCRIBE THE ANALYSIS YOU CONDUCTED OF THE ESTIMATED COSTS TO DEVELOP THE GREENLINK PROJECTS.

A. I reviewed the costs of Greenlink as approved by the PUCN in 2021⁹ and compared that cost estimate against the most recent cost estimate provided with NV Energy's 2024 IRP filing. I studied how the two cost estimates changed to identify the main drivers of cost changes and develop an apples-to-apples analysis of the cost increase since 2021. I compare the increase in estimated costs for the Greenlink projects to the recent trend in transmission infrastructure costs in the industry.

19. Q. HOW HAVE GREENLINK'S COSTS CHANGES SINCE THE PUCN'S APPROVAL OF THE PROJECTS IN 2021?

A. The estimated cost of the Greenlink projects approved by the PUCN in 2021 was \$2.5 billion.¹⁰ The most recent estimated cost of the projects is \$4.2 billion.¹¹

⁹ See Direct Testimony of Shahzad Lateef.

¹⁰ See Direct Testimony of Shahzad Lateef

¹¹ See Direct Testimony of Shahzad Lateef

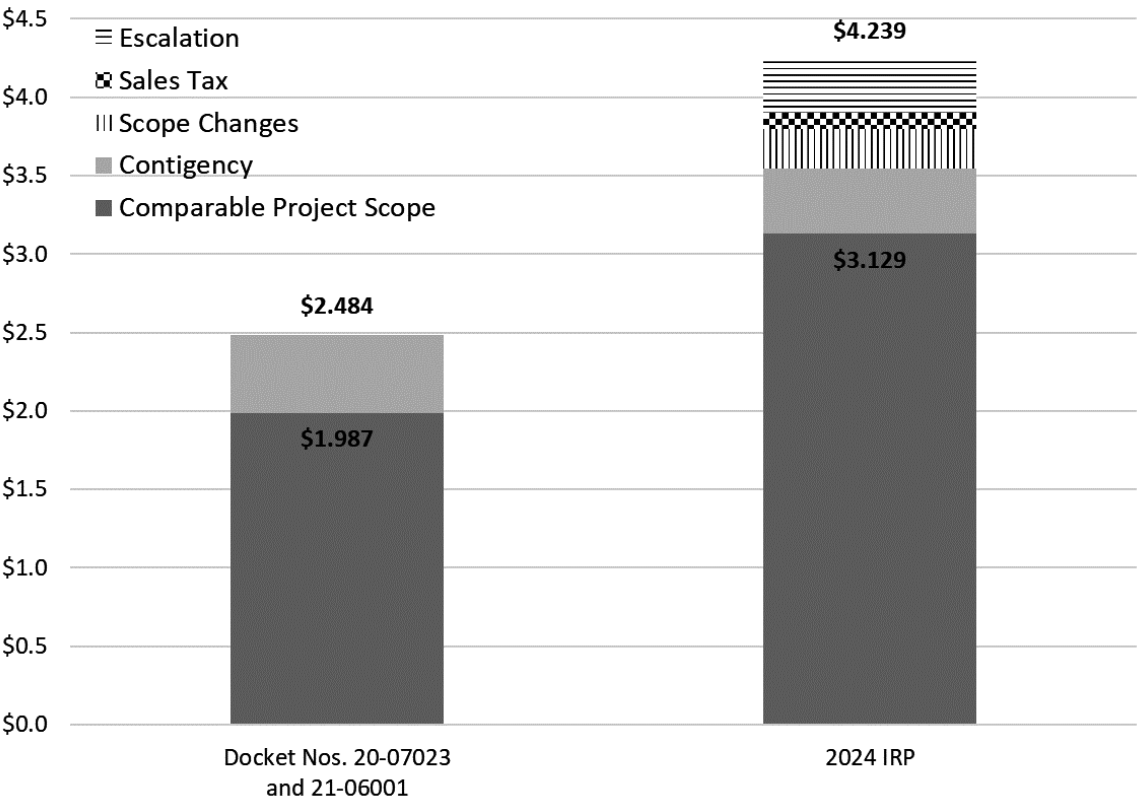
20. Q. **WHY HAVE GREENLINK'S ESTIMATED COSTS INCREASED SINCE 2021?**

A. Figure PF-6 shows the increase in estimated costs for the Greenlink projects from 2021 to 2024 and illustrates what has driven the increase in estimated costs over that time. In 2021, NV Energy estimated it would cost \$1.987 billion to complete the Greenlink projects as originally scoped (the dark grey bars) and included a contingency of almost \$500 million (the light grey bars), totaling to almost \$2.5 billion. As shown by the vertical line bars in the 2024 cost estimates, the scope of the Greenlink projects has expanded. The expanded scope of the projects added \$252 million to the cost estimate in 2024. The 2024 cost estimate includes two types of costs that were not included in either of the earlier cost estimates—sales tax (the checkerboard bar) and escalation¹² (the horizontal line bar)—that add \$442 million to the cost estimate. Lastly, the contingency included in the estimate cost of Greenlink evolved between the three estimates (the light grey bars) and is slightly lower in the latest estimate than it was in 2021, which reflects the fact that project costs are known with more certainty now that NV Energy is closer to the construction phase.

Comparing the estimated costs to complete the project as originally scoped (the dark grey bars) provides an apples-to-apples analysis of how the estimated costs of Greenlink have changed since 2021. Based on the same project scope as in 2021, the estimated costs of Greenlink have increased from \$1.987 billion to \$3.129 billion, or by approximately 16 percent per year from 2021 to 2024.

¹² Escalation accounts for known increases in costs that will occur between 2024 and the project in-service date. For example, contracts for labor state that wages will increase by a specified percentages each year. This type of cost escalation was unknown in 2021 or 2023 but is now known since NV Energy has begun to receive bids for materials and labor.

**FIGURE PF-6: GREENLINK PROJECT COST INCREASE SUMMARY
(NOMINAL \$BILLION)**



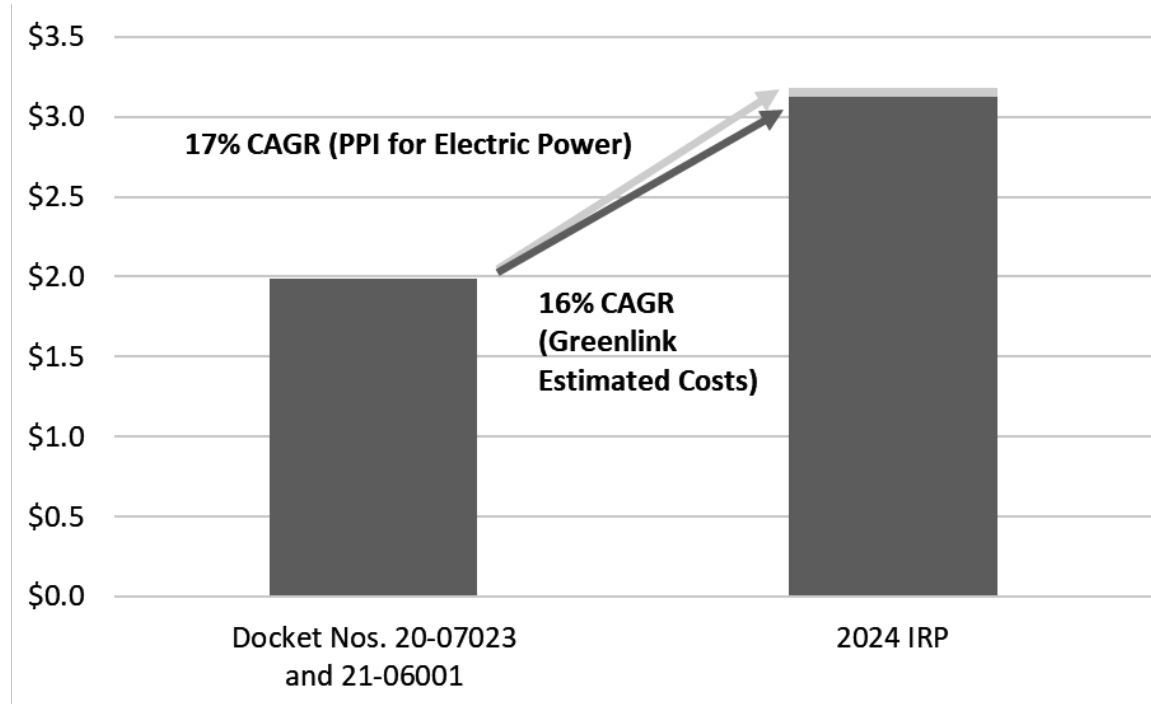
21. Q. IS THE 16 PERCENT PER YEAR INCREASE IN GREENLINK’S COSTS COMPARABLE TO COST INCREASES EXPERIENCED IN THE INDUSTRY FOR TRANSMISSION INFRASTRUCTURE?

A. Yes. The Bureau of Labor Statistics (BLS) tracks inflation for different commodities, including for several that contribute to the cost of transmission bulk electric power infrastructure. I reviewed the BLS Producer Price Indices (PPIs) for categories representing the majority of the components that would contribute to Greenlink costs, including Electric Power and Specialty Transformer Manufacturing, Power Wires and Cables, Power and Distribution Transformers, and Switchgear and Switchboard Apparatus. I additionally reviewed BLS wage growth indices for private industry construction workers. Across these categories,

I find that the average costs of equipment and labor increased by 62% between 2021 and 2024, which translates to a compound annual growth rate of 17 percent per year.

Figure PF-7 compares the growth rate in the estimated costs of Greenlink to the growth rate of a composite of PPIS related to electric power infrastructure and wage growth indices. If the estimated cost of Greenlink grew at the same rate as the related PPIS, the most recent estimated cost of the project (based on the original scope and without sales tax, contingency, or escalation) would have grown from roughly \$2 billion to \$3.2 billion, instead of roughly \$3.1 billion. In other words, the change in estimated costs for Greenlink between 2021 and 2024 is about \$54 million lower than it would be if estimated costs had grown at the pace of the relevant PPI and labor indices.

FIGURE PF-7: GREENLINK ESTIMATED COST INCREASE COMPARED TO POWER SECTOR-RELATED PPIS (NOMINAL \$BILLION)



V. Conclusions

22. Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I find that Greenlink creates over \$900 million of operational and market benefits for NV Energy customers over the lifetime of the projects, in addition to the investment, resource adequacy, and reliability customer benefits discussed by NV Energy witnesses.

Greenlink provides economic benefits to the state of Nevada by directly creating over 3,200 FTE jobs in the state, and indirectly creating an additional 3,400 FTE jobs in the local economy (over 6,800 total FTE jobs in the state). In addition, Greenlink will generation \$1.1 billion/year in economic stimulus benefits in local Nevada communities.

The Greenlink projects will provide additional benefits to NV Energy customers that are not quantified in my testimony. These include deferring or avoiding potential future transmission investment needed to maintain system reliability, increasing the resiliency of the NV Energy system by creating additional transfer capability between the NVE-S and NVE-N systems, accommodating load growth and future transmission service requests, increasing the interconnection with neighboring entities in the region to increase the customer benefits from NV Energy's participation in the WRAP and a potential future RTO in the WECC.

Lastly, I analyze how the costs of Greenlink have increased over the last four years. I control for changes in scope of the projects, differences in contingency assumptions, different applications of future project cost escalation, and sales tax costs to make an apples-to-apples analysis of how Greenlink's estimated costs have changed since 2021. I find that a comparison of the same cost categories for the

1 same project scope indicates that Greenlink's costs have increased from roughly \$2
2 billion in 2021 to \$3.1 billion in 2024, an increase of roughly 16 percent per year.
3 This cost increase is lower than the average increase seen across the Bureau of
4 Labor Statistics' PPIs related to electric power infrastructure and wage growth, the
5 average of which increased at a CAGR of approximately 17 percent per year
6 between 2021 and 2024. Therefore, the cost increase experienced on the Greenlink
7 projects is slightly less than industry-wide inflation experienced over the last
8 several years for similar transmission projects.
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10 **23. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

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EXHIBIT TSOUKALIS-DIRECT-1

John H. Tsoukalis

PRINCIPAL

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Mr. John Tsoukalis is a Principal at The Brattle Group specializing in electric power sector economics, modeling, and regulation. His expertise includes analyzing and designing alternative transmission rate designs, assessing the effectiveness of transmission planning processes and designing improvements to planning processes, and conducting benefit-cost analyses of generation and transmission infrastructure. He is experienced in assessing the value of transmission rights, analyzing the effectiveness of transmission cost allocation processes, and helping transmission developers to analyze investment opportunities in the US and Canada. His experience extends to conducting nodal production cost and power flow simulations of wholesale markets and regional power systems.

His work has been used to assess the benefits of transmission infrastructure, participation in wholesale power markets, joint regional unit commitment and/or dispatch, and consolidated balancing area operations. He has conducted production cost simulation models to value regional transmission infrastructure and trading rights, assessed the operation of regional transmission systems, analyzed the operation and value of generation assets in bilateral and organized regional power markets, and for the assessment of potential market manipulation and market power abuse in wholesale power markets.

Mr. Tsoukalis has worked with Independent System Operators (ISOs), Regional Transmission Organizations (RTOs), cooperatives, public power authorities, and investor-owned utilities on a wide range of issues related to wholesale power markets. He is experienced in helping ISOs/RTOs and utility clients analyze and design market rules to increase the efficiency of existing wholesale market operations, including the design of transmission charges, operating reserve products, and market power mitigation rules and procedures.

He has testified before the U.S. Federal Energy Regulatory Commission (FERC) and the Alberta Utilities Commission (AUC) in matters related to transmission rate design, transmission cost allocation, and transmission rate cases. He has testified in U.S. District Court in a dispute related to emergency wholesale market transactions. He has provided expert opinions to FERC related to the development and improvement of effective regional transmission planning and cost allocation processes, as well as the efficient design of ancillary services. His work on market design and the simulation of wholesale power markets has been filed with FERC and U.S. state

regulatory authorities, and he has supported the development of testimony in front of FERC and state regulatory authorities to assist with the design of ancillary service products, the appropriate tariff provisions to allow for adequate cost recovery, and to help develop tests for identifying and mitigating potentially manipulative behavior.

AREAS OF EXPERTISE

- Benefits and costs of wholesale power markets and regional coordination
- Production cost modeling
- Market design in wholesale power markets
- Analysis of GHG policy and implementation in wholesale markets
- Transmission rate design and cost of service studies
- Transmission cost-benefit analyses
- Electric utility strategic planning
- Resource planning and asset valuation
- Market manipulation detection and damages analysis
- Analysis and mitigation of market power
- Competitive transmission

EDUCATION

- **Universitat Autònoma de Barcelona, Spain**
M.Sc. in Economic Analysis, 2012
- **Barcelona Graduate School of Economics, Spain**
M.Sc. in Economics, 2010
- **Washington and Lee University**
B.A. in Economics with Honors, 2006

PROFESSIONAL EXPERIENCE

Power System Modeling

- Analysis of the Benefits and Cost of Membership in the Proposed Extended Day-Ahead Market (EDAM) and Markets+.** On behalf of several utilities in the western U.S., simulated the benefits and costs of participation in the two proposed regional day-ahead markets in the WECC. Simulated the existing bilateral markets in the WECC, including block trading at the major hubs in the region, intertie trades at the existing RTO seams, and existing real-time imbalance markets. Simulated important market design features of the proposed day-ahead markets, including the use of transmission rights in the markets, the market structures used to restrict and price imports into states with GHG pricing regimes, and the accounting and allocation of congestion revenues collected by the markets. Presented results of the analysis to seven different state commissions in the WECC.
- Valuation of Generation Asset in the Bilateral Power Markets in Florida.** On behalf of an independent power producer, developed a market simulation and resource planning model of the Florida power system. Analyzed the value of a new gas-fired generation resource in Florida in the existing bilateral market structure in the state and under various assumptions on future resource costs. Calculated unit-level operation for a new gas-fired resource and determined the net present value of the asset.
- Analysis of Benefits and Costs of Market Reforms for Customers in South Carolina.** On behalf of the South Carolina legislature, analyzed the benefits and costs to customers of numerous different market reform options for the state, including wholesale, retail, and system planning reforms. Developed a customized model, with input and data from a group stakeholders, of the entire Southeastern U.S. including the Carolinas, Southern Company, all of the Florida utilities and cooperatives, TVA, PJM, and MISO. Simulated the Southeast Energy Exchange Market (SEEM) and the other bilateral markets that existed through the Southeastern U.S. and compared the operation of those markets to various types of potential wholesale market designs and footprints.
- Analysis of Extended Day-Ahead Market (EDAM) in the WECC.** On behalf of a group of utilities in the WECC, simulated the proposed Extended Day-Ahead Market (EDAM) and estimated the benefits of the joint unit commitment and dispatch, pooled transmission rights, and reserve sharing and joint provision under the proposed market structure. Represented the proposed GHG-accounting structure in the EDAM market footprint for transactions across states with GHG policies and states without policies. Represented the bilateral markets in the WECC, including utility-specific unit commitment and dispatch

decision-market, trading hubs, block trading, trading margin requirements, wheeling fees, and limited transmission rights/transfer capability between utilities. The bilateral market was compared to the regional market case to estimate benefit metrics.

- **Analysis of Operation of Proposed Wind Farm in Colorado.** On behalf of a renewable developer in the WECC, analyzed the patterns of congestion and curtailments in the Colorado-Wyoming region. Simulated operation of a proposed wind farm under the existing bilateral markets and real-time imbalance markets, and under the proposed SPP West RTO market. Determined exposure to congestion and curtailment risk for the proposed wind resources.
- **Analysis of Generation Resource Investment and Retirement Decision in Alberta.** On behalf of a generation owner in Alberta, simulated investment, retirement, and operational outcomes for the Alberta power pool through 2050. The analysis used Brattle's GrimSIM capacity expansion modeling software to determine the profitability of various generation resource types, prices in the AESO market, investment decisions in new resources, and retirement decisions for existing resources. The analysis accounted for the proposed federal decarbonization policies. Analyzed the change in resource mix in the province needed to comply with proposed policies, operational outcomes for client-owned generation assets, pool prices in the province, and the impact of new generation assets on the exercise of market power on pool prices.
- **Analysis of Market Participation Benefits.** On behalf of a group of cooperatives, municipal utilities, and federal power authorities in the WECC, simulated the benefits of joining the proposed Southwest Power Pool (SPP) West RTO. Modeled the bilateral markets in the region and the joint unit commitment, economic dispatch, optimization of the DC ties between SPP and the WECC, and then pooled reserve procurement under the proposed SPP West RTO.
- **Analysis of the Western Energy Imbalance Service and SPP West RTO.** On behalf of the Southwest Power Pool, conducted a production cost simulation of the Eastern Interconnection and WECC to assess the benefits from creating the Western Energy Imbalance Service (WEIS) and from extending the SPP RTO market into portions of the WECC. Analyzed how transmission systems would operate under the new market structure, including the DC interties that connect the Eastern Interconnection and the WECC and the transmission systems in both interconnections. Calculated benefits for market participation for the utilities interested in joining the new market and for the existing utilities in SPP.

- **Analysis of Participation in Regional Energy Imbalance Markets.** On behalf of Black Hills Corp., Colorado Springs Utilities, Platte River Power Authority, and Xcel Energy, analyzed the production cost benefits from participation in the CAISO-administered Western Energy Imbalance Market and the proposed SPP-administered Western Energy Imbalance Service. Conducted several production cost simulations testing multiple scenarios and wrote report summarizing procedure and findings. The report was filed with the Colorado PUC in a proceeding to explore market participation for Colorado utilities.
- **Analysis of Participation in Regional Energy Imbalance Markets.** For an investor-owned utility in the western U.S., estimated the benefits of participating in an energy imbalance market. Simulated membership in two energy imbalance market options and analyzed the relative gains from each option.
- **Analysis of Regional Market Alternatives for the Mountain West Transmission Group.** For the eight members of the Mountain West Transmission Group in Colorado, Wyoming, and neighboring states analyzed the costs and benefits of alternative regional transmission and market options. The regional transmission and market analysis included detailed market simulations and estimation of member costs and benefits for (a) retaining the current bilateral market construct; (b) forming a regional transmission group with de-pancaked transmission service; and (c) forming or joining a full “Day 2” regional wholesale power market. The results informed the clients’ decision to explore regional market alternatives with existing RTOs.
- **Analysis of Resource Planning Options.** For a municipal utility in the western U.S., simulated system operations and estimated production costs under several potential future resource portfolios and potential market participation scenarios under consideration by the utility. Results were relied upon by the utility to inform resource planning and market participation decisions.
- **Analysis of Participation in a Regional Wholesale Power Market.** For a group of electric cooperatives, public power authorities, and investor-owned utilities in the western U.S., estimated the benefits of participating in a regional wholesale power market. Simulated membership in a proposed regional wholesale power market under different potential future scenarios and estimated the benefits from participation for each member in the group. Results of the simulations, including the estimated benefits of membership in the market, were relied upon to inform the clients’ decision making regarding joining the proposed market.

- **Valuation of Strategic Investments.** For a private equity firm, estimated the long-term value of two generation assets owned by the firm. Simulated energy revenues for the generation assets under multiple future scenarios to consider the impact of energy policy changes, renewable energy penetration, fuel price changes, and participation in regional wholesale powers markets.

Transmission Benefits Analysis, Rate Design, and Investment

- **Testimony in Transmission Rate Recovery Proceeding.** On behalf of New York Transco LLC, provided expert testimony in front of the Federal Energy Regulatory Commission (FERC) analyzing the case for transmission incentives for the Propel NY Energy project. Assessed recent FERC Orders granting transmission incentives (Construction Work in Progress in Rate Base, Project Abandonment, and ROE Incentive Adders) and compared the risk profile of the Propel NY Energy projects against projects that have been awarded similar incentives. Provided a review of FERC precedent and legislative mandate for transmission incentives and established the benefits of transmission incentives for customers and transmission developers.
- **Transmission Benefit-Cost Analysis in the WECC.** On behalf of a utility in the WECC, analyzed the benefits of proposed transmission infrastructure. Simulated power markets in the western U.S. to determine the customer savings created by the new transmission infrastructure. Calculated the following benefit and cost metrics: reduced fuel costs, lower operating costs, emissions reductions, the increased sale of short-term transmission service, higher congestion revenues allocated from regional wholesale power markets, higher bilateral trading profits for the utility, job and economic stimulus impacts of the investment, avoided generation interconnection costs, avoided or deferred reliability investments and upgrades, resource adequacy benefits. Presented findings to the state commission.
- **Analysis of Net Power Cost Pass Through Mechanism.** On behalf of an electric utility in the WECC, analyzed the net power cost pass through mechanisms imposed by their state commission and assessed how participation in a regional day-ahead wholesale power market would influence the utility's ability to reduce net power costs for their customers, including the impact of security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) on optimizing the operation of the client's generation and transmission assets. Compared the net power cost pass through mechanisms the client is subject to with mechanisms in states with a similar regulatory and market construct.

- **Assessment of a Utility's Power Market Model used for Net Power Cost Forecasting.** On behalf of an electric utility in the WECC, reviewed their internal models of wholesale market markets in the region and helped them assess how accurately their modeling captures the dynamics of the existing bilateral markets in the WECC and proposed regional day-ahead markets. The analysis was used to inform their net power cost filings with their state commission and to assist utility leadership in making decisions on membership in proposed regional wholesale power markets.
- **Analysis of Local Network Service Transmission Rates in ISO-NE.** On behalf of a generation owner in ISO-NE, analyzed the rate they pay for local network service and helped them determine the key drivers for recent rate increases. Assisted the client in developing strategies for mitigating their transmission rates in the future.
- **Analysis of Market for Rights on a Proposed Transmission Asset and Support of Application for DOE Funding.** On behalf of a transmission developer in the WECC, supported their winning application for funding under DOE's Transmission Facilitation Program. Prepared an analysis of market benefits for the proposed transmission line, including an assessment of demand for rights on the line and likely off takers. Presented results to DOE in a written report and responses to DOE questions, as well as in-person at final round interviews with DOE staff. The project was ultimately selected by DOE based on the likelihood that the project would be developed and that the rights purchased by DOE would be successfully re-sold.
- **Transmission Benefit-Cost Analysis for Proposed Transmissions Assets in the WECC.** On behalf of an investor-owned utility and independent transmission developer in the WECC, analyzed the benefits and costs of a proposed portfolio of transmission projects. Simulated the bilateral power markets in the region and the WEIM and analyzed the cost of renewable energy resources that can be integrated through the new transmission compared to higher-cost resources that would be developed with the new transmission. Calculated multiple benefit and cost metrics for the proposed transmission assets, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.
- **Transmission Benefit-Cost Analysis for Proposed HVDC Transmission Line between SPP and the WECC.** On behalf of a merchant transmission developer, calculated numerous benefit and cost metrics for a proposed 100-mile HVDC line with a capacity of 3,000 MW that would connect the SPP RTO with major trading locations in the WECC. Simulated the SPP RTO market and the proposed day-ahead regional power markets in the WECC to assess the benefits of the proposed project. Calculated numerous benefit metrics for the proposed

line, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.

- **Transmission Benefit-Cost Analysis for Proposed HVDC Transmission Line between SPP and MISO.** On behalf of a merchant transmission developer and an investor-owned utility, calculated numerous benefit and cost metrics for a proposed 400-mile HVDC line that would connect the SPP and MISO markets. Simulated the SPP and MISO RTO markets to assess the benefits of the proposed project. Calculated numerous benefit metrics for the proposed line, including adjusted production cost, emissions reductions, resource adequacy benefits, reduced congestion, and avoided or deferred reliability upgrades.
- **Testimony in Transmission Rate Design Proceeding.** On behalf of Capital Power, provided expert testimony in front of the Alberta Utilities Commission (AUC) analyzing the impacts of a proposed new transmission tariff design provided by the Alberto Electricity System Operator (AESO). Analyzed the increase in uneconomic bias caused by the proposed tariff design and cost shifting to other customers in the province. Provided written and oral testimony in front of the AUC.
- **Testimony in Support of Transmission Rate Case Filing.** On behalf of Portland General Electric, provided testimony before the FERC in support of their transmission rate case. Testimony supported the transmission cost of service study filed as part of the rate case and provided explanation on key input and components of the cost-of-service study, including the drivers of change in the company's costs service.
- **Testimony in Transmission Cost Allocation Proceeding.** On behalf of GridLiance High Plains LLC, provided testimony before the FERC on the benefits of transmission assets. Conducted a shift factor analysis to determine how the assets are used to support regional power transfers. Analyzed transmission contingencies to assess if the assets alleviated system overloads under contingency conditions.
- **Testimony in Transmission Cost Allocation Proceeding involving the Seven Factor and Mansfield Tests.** On behalf of GridLiance High Plains LLC, provided testimony before the FERC applying FERC's Seven Factor Test and Mansfield Test to a set of assets the company was seeking to place in the SPP regional transmission tariff. Applied shift factor and electrical distance analysis to determine how the integration of the assets the relevant zone of SPP. Testimony resulted in a favorable initial decision from the FERC Administrative Law Judge.
- **Design of Transmission Access Charges.** For the California ISO, developed an analysis of cost shifts between participating transmission owners due to different Transmission Access

Charges (TAC) structures. Results of the analysis were used by the CAISO in stakeholder engagement during an initiative aimed at re-designing the TAC.

- **Strategic Transmission Planning and Rate Analysis.** For an integrated electric utility client, analyzed the qualitative and quantitative benefits of participating in a joint transmission tariff with interconnected transmission owners. Analyzed the impact on transmission rates for this utility. Identified and assessed additional regional integration options for this utility client, including participation in an existing energy imbalance market, membership in an adjacent RTO, and the development of new regional markets with interested neighbors.
- **Transmission Investment Opportunities Assessment.** For several transmission owners and developers, projected the investment need for transmission infrastructure over the next ten years in all U.S. planning regions. Provided analysis of the different drivers of this investment need and studied the implementation of competitive bidding processes for transmission projects as mandated by FERC Order 1000. Helped create forecasts on the amount and type of competitively sourced transmission investment in each planning region across the U.S.
- **Analysis of the Benefits of Transmission Investment.** For an investor-owned utility, analyzed the reliability and economic impact of over \$3.5 billion in capital expenditures to upgrade and harden their existing transmission assets. The reliability benefits analysis estimated a reduction in lost load due to the transmission investments and applied a value of lost load to the reduction. The economic benefits analysis relied on an input-output model analysis to determine the economic activity, job creation, and tax revenues generated by the upgrades to existing transmission facilities. The results of the analyses were used to support internal decision making on capital expenditures and for discussion purposes with policy makers in the states where the utility operates.
- **Analysis of the Benefits of New Transmission Assets.** For an investor-owned utility, analyzed the economic impact of investing in a new transmission line. The analysis relied on an input-output model analysis to determine the economic activity, job creation, and tax revenues generated by the construction of the new transmission facility. The results were used in testimony in front of two state regulatory commissions.
- **Competitive Transmission Opportunity Assessment.** On behalf of a competitive transmission developer, assessed the opportunity for competitive transmission projects. Analyzed transmission investment needs in each region of the U.S. and reviewed the transmission planning processes and competitive project requirements in each region. Conducted a focused analysis of competitive opportunities in several RTO markets.

- **Analysis of Transmission Rate Design.** For a transmission owner in an ISO market, analyzed the performance of the transmission rate design based on criteria established by the market administrator. Developed alternative rate design proposals for use in the public stakeholder process.
- **Long-Term Transmission Planning.** Supported the development of testimony filed on behalf of a regional transmission planning entity in front of a state regulatory commission. Analyzed the forecasts and model utilized by the planning entity to recommend specific transmission projects. Provided guidance to the commission on the reasonableness of the process implemented by the planning entity relative to industry practices.
- **Evaluation of a Transmission Utility.** For a potential investor, contributed in the effort to evaluate a transmission utility. Helped estimate the size of future rate base through a study of proposed transmission projects within the utility's service territory. Leading to an assessment of the likelihood each project would get regulatory approval and ultimately be built and contribute to rate base.
- **Retail Electric and Water Rate Design.** For a municipal electric and water utility in the western U.S., reviewed utility's electric retail rate structure and retail water rate structure. Conducted benchmarking study against similarly positioned electric and water utilities in the region. Provided recommended changes to the rate structures for both water and electric power. Analyzed the rate impact of incorporating on new water customers for existing water customers.

Wholesale Market Design

- **Expert Report in U.S. District Court in Contract Dispute Related to Bilateral Transactions at Southwest Power Pool (SPP) Seam.** On behalf of an electric cooperative, provided expert report in front of a U.S. District Court. Analyzed the cost of providing bilateral energy sales at the SPP market seams compared to the revenues.
- **Wholesale Market Price Formation and Fast-Start Resource Integration.** For an SPP market participant, analyzed inefficiencies in wholesale price formation and the commitment and dispatch of fast-start resources. Worked with client and SPP teams to developed recommendations and presented them in an affidavit before the FERC.
- **Ramping Product Design.** On behalf of an SPP market participant, drafted a white paper on efficient and effective methods and best practices for designing an ancillary service product to procure ramping capacity. Collaborated with SPP staff and the SPP market monitor to

develop the best design principles for the ramping product and to integrate that product into SPP's existing day-ahead and real-time energy and ancillary services markets.

- **Design of Ontario Market Power Mitigation Regime in Capacity Auction.** For the IESO, developed methodology for calculating the resource-specific offer caps to be used as part of the market power mitigation regime in the Capacity Auction in Ontario. Public report was issued with recommended approach for use in the stakeholder process and to inform public discussion on the offer cap design.
- **Capacity Auction Design.** For an ISO client, analyzed proposed auction design and provided recommendations on improving the design. Tested the auction clearing and price formation mechanisms to ensure optimal outcomes are achieved and efficient prices are produced from the auction. Provided several recommended changes to the clearing mechanism and price formation procedure, which were utilized by the client to improve the auction design.
- **Financial Transmission Rights (FTRs) Market Design.** For an ISO client, reviewed the existing transmission rights market in the region and developed recommendations for amending FTR market design, including an examination of whether the FTR market provided benefits for load in the region.
- **Ontario TR Market Design.** On behalf of the IESO, reviewed experiences in other regional markets and advised IESO staff on the methodology for allocating surplus congestion rents and TR auction revenues. Co-authored a public report with recommendations on updating the method for distributing congestion account surplus to Ontario market participants.
- **Alberta Capacity Market Design.** On behalf of the AESO, collaborated with AESO staff to develop features of the proposed forward capacity market for Alberta.
- **Ontario Capacity Market Design.** On behalf of the IESO, advised IESO staff on the design of the proposed forward capacity market for Ontario.
- **Assessing the Impact of Dynamic Pricing.** For a regional transmission organization, analyzed the impact of different dynamic rate designs on their system. Focused on determining the reduction in peak load and total energy consumption. Estimated the monetary benefits derived from those reductions. Presented results and the models utilized to internal stakeholders.

Analysis of Clean Energy Markets, Decarbonization Policy, and Environmental Regulation

- Analysis of the Market for Clean Energy in the WECC.** On behalf of a utility in WECC, analyzed the bilateral market for clean energy in the western U.S. with specific focus on the Pacific Northwest region. Assessed the planned clean energy resources in the western U.S. and compared against the projected demand for clean energy based on state policies. Calculated an hourly supply of available clean energy, defined as clean energy production that is not claimed by any other load-serving entities to comply with their state policies. Determined a premium for clean energy in each hour relative to bilateral market power prices.
- Analysis of Proposed U.S. Treasury Rules for Hydrogen Tax Credits.** On behalf of Los Angeles Department of Water and Power, analyzed the proposed regulations (Section 45V rules) on the clean hydrogen production tax credit established by the Inflation Reduction Act (IRA). Assessed how the proposed rules align with the operation of power markets and typical resource planning practices in the western U.S. Proposed alternative approaches for the U.S. Treasury to consider that would reduce compliance cost and ensure qualifying hydrogen production would be clean. Developed a white paper that was filed as part of LADWP's comments on the proposed rules.
- Simulation of Wholesale Market GHG Rules in the WECC.** On behalf of several utilities in the western U.S., modeled the proposed GHG market rules in EDAM and Markets+. Simulated the two proposed day-ahead markets and analyzed the operation of both GHG structures on price formation, GHG emissions, and transfers into GHG-pricing states under each market.
- Analysis of Clean Energy Supply and Demand in British Columbia.** On behalf of a natural gas producer in British Columbia, analyzed the likely demand for clean energy resources in the province considering decarbonization policies and projected electric load growth. Assessed the economic and technical potential to develop various types of clean energy resources in the province, including the cost of new clean energy resources. The results of the analysis were used by the client to assess the potential to electrify their natural gas production operations in the province, including a potential new liquified natural gas export facility.
- Simulation of Alberta Power Market under Proposed Federal GHG Reduction Policies.** On behalf of a generation owners in Alberta, simulated investment and operational outcomes for the Alberta power pool through 2050 accounting for proposed federal GHG reduction policies. Analyzed the change in resource mix in the province needed to comply with proposed policies, operational outcomes for client-owned generation assets (and other

asset-types in the province), pool prices in the province, and the impact of new generation assets on the exercise of market power on pool prices. Supported client in discussions with federal policy makers.

- **Analysis of Market Participation Benefits under GHG Policies.** On behalf of a cooperative in Colorado, simulated participation in the SPP West RTO under the proposed Colorado GHG policy. Simulated the dispatch cost of GHG in Colorado resources, and the cost of importing generation from out-of-state emitting resources in both a bilateral market setting and the RTO setting.
- **Analysis of Proposed EPA GHG Standards.** For a group of utilities in the WECC, analyzed the impact of the proposed rule on their generation assets, reviewed alternative compliance paths with the utility subject matter experts, and assisted in the preparation of the comments to be submitted to EPA.
- **Review of GHG Accounting Mechanisms in the WECC.** For WEST Associates, a group of utilities in the WECC, cataloged the GHG and clean energy accounting methodologies in use across the western U.S., including RPS, energy supply disclosures, GHG reporting and reduction rules, and voluntary reporting. Wrote a white paper presenting the findings.
- **Analyze of Market Options for Clean Power in the WECC.** On behalf of a renewable developer in the WECC, assessed the market opportunities for their wind farms after existing PPAs expire. Analyzed future market prices at different potential points of sales (e.g., the AESO market, Mid-C, the CAISO market). Provided information on potential operational hurdles and costs for bring their wind power to market under different strategies. Assessed the potential for coupling wind power with local hydro resources to deliver a firm clean energy product, and the market premium for that product relative to an energy only PPA.
- **Environmental Regulation Impact.** For a merchant power producer, assessed the impact of changes in the regulatory environment on the economic viability of coal-fired generation, particularly focused on the Mercury Air Toxics Standards (MATS) rule.

Resource Planning and Asset Valuation

- **Analysis of British Columbia Hydro and Power Authority's Resource Plan.** On behalf of a large power customer in British Columbia, analyzed the resource plan for BC Hydro including the estimated cost and demand for new resources available in the province. The analysis considered the decarbonization policies and related electrification load growth.

Assessed the potential for developing various types of clean energy resources in the province, including the cost of new clean energy resources.

- **Development of a Renewable Procurement Strategy.** On behalf of an electric utility in Canada, analyzed various options for procuring and delivering clean energy resources to their customers from neighboring provinces and U.S. states. Assisted the client in weighing different economic, development, and political risks related to different procurement strategies and analyzed the likely future supply and demand dynamics for clean energy resources in neighboring. Results of the analysis informed the client's clean energy procurement strategy.
- **Assessment of Reliability Under Deep Decarbonization Scenarios.** On behalf of a utility in MISO, analyzed their resource plan developed to comply with state decarbonization policies. Simulated the operation of their system under deep renewable penetration scenarios and assessed their ability to maintain reliable operation of the system. Results were used to support IRP decision making and as evidence in front of their state commission.
- **Valuation of Generation Assets in the WECC.** On behalf of a merchant generation owner in the WECC, analyzed the market opportunity for two gas-fired combine cycle resources in the bilateral power market in the WECC. Developed a forecast of energy and capacity revenues under different decarbonization policy scenarios and different wholesale market structures in the western U.S. Assessed the potential demand for energy and capacity from the assets based on resource plans of utilities in the region and state decarbonization policies. The results informed the clients power marketing strategy after the expiration of existing PPAs for the assets.

Analysis of Market Manipulation, Compliance, and Wholesale Market Disputes

- **Analysis of Potential Merger in Alberta.** On behalf of a generation owner in Alberta, analyzed the impact on prices from a proposed merger between two major generation owners in the province. Supported client in comments and presentation before the Canadian Competition Bureau.
- **Breach of Contract Dispute related to Wholesale Power Transactions.** On behalf of Associated Electric Cooperative, Inc. (AECI) analyzed the cost of supplying emergency power into SPP during Winter Storm Uri and compared cost with payments received through SPP settlement. Estimated damages in the form of unrecovered costs for producing the emergency power. Prepared an expert report filed in U.S. Federal District Court.

- **Compliance Investigation in New Zealand.** For Meridian Energy, analyzed claims made by other market participants and by the Electricity Authority (EA) alleging an undesirable trading situation (UTS) due to Meridian's behavior, and submitted comments to the EA.
- **Compliance Plans for Generation Owners.** For a generation owner in Europe, assisted in-house compliance team in the development of compliance procedures and rules tailored to the specific offer strategies and forecasting methodologies relevant to their generation fleet.
- **Wholesale Electricity Market Manipulation.** For a generation and transmission cooperative in the Southwest Power Pool (SPP), developed analyses to detect potential manipulative behavior in the methodology used to offer their units into the wholesale market. These analyses were used to assess the exposure to regulatory liability and present arguments in front of the FERC.
- **Development of Screens to Detect Manipulation in Electricity Markets.** For several generation owners or power trading firms, designed screens to assist with the detection of a wide variety of behavior relevant to electric power market, including the inappropriate withholding of generation to benefit related positions, the uneconomic or fraudulent offer of generation to garner out-of-market payments, and the use of uneconomic physical or virtual price-making trades to impact the value of price-taking positions. Also evaluated specific types of "gaming" behavior and other types of trades (such as circular schedules, "sham" schedules or "wash-like" transactions) that could be viewed as manipulative.
- **Wholesale Electricity Market Manipulation.** For a generation owner in PJM, supported the construction of analyses to detect uneconomic behavior in the methodology used to offer their units into the wholesale market, as well as estimated any potential price suppression and harm caused to other generators. These analyses were used to assess the exposure to regulatory liability and to calculate possible damages.
- **Uneconomic Bidding.** For a merchant power provider, helped draft testimony filed with a regulatory body to provide clarity in its attempt to establish the proper definition of uneconomic bidding in the wholesale electricity market. Specific focus was paid to the bidding behavior of coal-fired power plants in day-ahead markets.
- **Electric Utility Rate Disputes.** As part of an electric utility rate case, aided in the development of testimony analyzing the financial wellbeing of a large industry customer. The testimony centered on determining the validity of the industrial customer's claimed need for rate relief.

- **Prevention of Manipulation in Capacity Markets.** Assisted in writing testimony filed in a tariff revision proceeding in front of the FERC. Provided guidance for an RTO in crafting tariff provisions to prevent and properly mitigate manipulative bidding behavior in its capacity market.
- **Prevention of Manipulation in Capacity Markets.** Assisted in writing testimony filed in front of the FERC. Provided guidance on developing market rules and procedures to prevent the manipulation of capacity auctions by imported resources.

Electric Power Strategic Planning

- **Development of a Regulatory Action Plan.** For an investor-owned utility and renewable developer, led a strategic planning initiative to engage policy staff across the organization to establish key policy areas for the organization. Specific policy objectives were created to focus policy advocacy, identify action items for the next 18 months of advocacy, and identifying a longer-term strategic plan for engaging commissions, market operators, and policymakers on the organizations key policy areas beyond the 18-month time frame. Developed a strategic action plan document establishing the regulatory action items for the organization.
- **Development of Strategic Action Plan.** For a cooperative in ERCOT, led a strategic planning initiative to engage with the board of directors to establish their vision for the organization, including core values for the organization to pursue as well as specific and actionable strategic priorities for senior management to implement. Created a framework to ensure the strategic priorities remained up to date and relevant for the cooperative and its members and to ensure that the board remained continually engaged on strategic issues. Led a strategic planning workshop for the cooperative's board of directors and utilized the output of workshops to create a strategic action plan document memorializing the core values, strategic priorities, and engagement framework.
- **Review and Development of Strategic Plan.** For a public power authority in SPP, led a strategic planning initiative to review existing strategic planning documents, guide the organization in creating an updated strategic plan, and helped create a framework for assessing evolving industry trends going forward. Led a strategic planning workshop for the C-suite and all senior management in the organization and used output of workshop to develop strategic initiatives and milestones for the utility.
- **Strategy Planning for Energy Transformation.** For a public power authority in the Southwest Power Pool (SPP), led a strategic planning initiative to address myriad issues

confronting the utility in the near future. The initiative covered de-carbonization, evolving customer preferences, human resource issues, reliability, data and IT challenges, and customer costs. Conducted strategic planning sessions with the executive team at the utility, which lead to the development of a strategic plan and de-carbonization proposal.

- **Integration of Emerging Technologies and Services.** For two distribution cooperatives, conducted a long-term strategic planning effort with executives and managers. Presented materials on technology trends, rate structure challenges and solutions, and challenges with regional transmission cost allocations and facilitated the development of long-term industry scenarios and strategic responses for a comprehensive corporate strategy.

TESTIMONY AND REGULATORY FILINGS

- Before the Federal Energy Regulatory Commission, Docket No. ER24-232-000, *Testimony of John Tsoukalis*, on behalf of New York Transco LLC, *re*: New York Transco LLC Proposed Rate Recovery Mechanism for Propel NY Energy Project, October 27, 2023.
- Before the United States District Court for the Western District of Missouri, Associated Electric Cooperative, Inc. vs. Southwest Power Pool, Inc., Case No. 6:22-cv-03030-BCW, *Expert Report of John H. Tsoukalis*, September 2, 2022.
- Before the Alberta Utilities Commission, Proceeding No. 26911, *Written Evidence of Johannes P. Pfeifenberger and John Tsoukalis*, on behalf of Capital Power Corporation, *re*: AESO Bulk and Regional Rate Design and Modernized DOS Rate Design Application, March 28, 2022.
- “Technical Review Committee’s Review of Duke Energy’s Solar Integration Service Charge (SISC),” coauthored with J. Pfeifenberger and S. Ross, filed with the North Carolina Utilities Commission, Docket No. E-100 Sub 175, November 1, 2021.
- Before the Federal Energy Regulatory Commission, Docket No. ER22-233-000, *Testimony of John Tsoukalis*, on behalf of Portland General Electric, *re*: Portland General Electric Company’s Transmission Rate Filing and Limited Revisions to Open Access Transmission Tariff, October 28, 2021.
- “Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs,” coauthored with J. Pfeifenberger, K. Spokas, J. Hagerty, R. Gramlich, M. Goggin, J. Caspary, and J. Schneider, filed with the Federal Energy Regulatory Commission, Docket No. RM21-17-000, *Comments of the American Council on Renewable Energy*, Exhibit 6, October 12, 2021.
- Before the Federal Energy Regulatory Commission, Docket No. ER18-99-005, *Rebuttal Testimony of John Tsoukalis*, on behalf of GridLiance High Plains LLC, *re*: Benefits of Transmission Assets and Regional Cost Recovery under the SPP OATT, July 15, 2021.
- Before the Federal Energy Regulatory Commission, Docket No. ER18-99-005, *Direct Testimony of John Tsoukalis*, on behalf of GridLiance High Plains LLC, *re*: Benefits of Transmission Assets and Regional Cost Recovery under the SPP OATT, April 20, 2021.
- “Response to Third Party Submissions Regarding Alleged UTS of 2019,” coauthored with P. Bagci and J. Reitzes, 10 November 2019, Undesirable Trading Situation Preliminary Decision Cross Submission filed with The New Zealand Electricity Authority, September, 16, 2020.

- “New Zealand Electricity Authority’s Preliminary Decision on UTS,” coauthored with P. Bagci and J. Reitzes, 10 November 2019, Undesirable Trading Situation Preliminary Decision Submission filed with The New Zealand Electricity Authority, August, 18, 2020.
- Before the Federal Energy Regulatory Commission, Dockets No. ER18-2358-001 and ER19-1357-000, *Rebuttal Testimony of John Tsoukalis*, on behalf of GridLiance High Plains LLC, *re*: Regional Cost Recovery under the SPP OATT for GridLiance transmission assets, March 27, 2020.
- “GridLiance System Analysis: Transmission Facility Classification,” prepared for GridLiance High Plains LLC, coauthored with J. Chang, March 27, 2020. Filed with the Federal Energy Regulatory Commission, Dockets No. ER18-2358-001 and ER19-1357-000.
- Before the Federal Energy Regulatory Commission, Docket No. ER20-644-000, *Affidavit of Johannes P. Pfeifenberger and John Tsoukalis*, on behalf of Golden Spread Electric Cooperative, *re*: Comments on SPP Compliance Filing Revising Fast Start Pricing Practices, January 21, 2020.
- “Joint Dispatch Agreement Energy Imbalance Market Participation Benefits Study,” prepared for Black Hills Corporation, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, coauthored with J. Chang, J. Pfeifenberger, S. Leamon, and C. Peacock, January 14, 2020. Filed with the Colorado Public Utilities Commission on January 28, 2020, Processing No. 19M-0495E, filing No. G 762524.

ARTICLES, PUBLICATIONS, AND PRESENTATIONS

- “NV Energy Day-Ahead Market Benefit Studies: Comparative Benefits for NV Energy of Joining EDAM versus Markets+,” presented to the Public Utilities Commission of Nevada, April 3, 2024.
- “Section 45V Clean Hydrogen Production Tax Credits: Comments on Proposed Treasury Guidelines,” prepared for the Los Angeles Department of Water and Power, coauthored with J. Figueroa, R. Sreenath, and E. Curtis, February 26, 2024.
- “Wholesale Markets and GHG in the WECC: Past, Present, and Future,” Law International Seminars Electric Power in the West, January 26, 2024.
- “Extended Day-Ahead Market Participation Benefits Study,” prepared for Balancing Area of Northern California, Idaho Power Company, Los Angeles Department of Water and Power, PacifiCorp, and Sacramento Municipal Utility District, coauthored with J. Pfeifenberger, K. Van Horn, and E. Bennet, December 2023.
- “MISO South Tranche 3 Transmission Planning and Cost Allocation,” Entergy Regional States Committee Meeting, co-presented with M. Hagerty, September 8, 2023.
- “Extended Day-Ahead Market Benefits Study,” presented to the EDAM Forum, August 30, 2023.
- “Greenhouse Gas and Clean Energy Accounting Methodology Catalog,” prepared for the WEST Associates, coauthored with K. Spees, J. Grove, and L. Lam, June 2023.
- “Brattle EDAM Simulations: PacifiCorp Results,” presented to the Wyoming Public Service Commission, Oregon Public Service Commission, Idaho Public Utilities Commission, and the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, coauthored with J. Pfeifenberger and E. Bennett, May-July, 2023.
- “Assessment of Potential Market Reforms for South Carolina’s Electricity Sector,” prepared for the South Carolina General Assembly, coauthored with K. Spees, J. Pfeifenberger, A. Levitt, A. Thompson, O. Kuzura, E. Bennett, S. Pon, M. Diehl, E. Curtis, S. Tang, and R. Nelson, April 27, 2023.
- “A Roadmap to Improved Interregional Transmission Planning,” prepared for the Natural Resources Defense Council, coauthored with J. Pfeifenberger, K. Spokas, and J. Hagerty, November 30, 2021.

- “The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York,” prepared for the New York State Energy Research and Development Authority, coauthored with J. Pfeifenberger and S. Newell, November 9, 2021.
- “Transmission Investment Needs and Challenges,” presented for JP Morgan Renewables and Grid Transformation Series, coauthored with J. Pfeifenberger, June 1, 2021.
- “2020 CAISO Blackouts and Beyond: The Future of California Resource Planning,” presented for LSI Electric Power in the West Conference, coauthored with F. Graves and S. Leamon, January 29, 2021.
- “Western Energy Imbalance Service and SPP Western RTO Participation Benefits,” prepared for the Southwest Power Pool, coauthored with J. Pfeifenberger, M. Celebi, S. Leamon, C. Peacock, and S. Ganjam, December 2, 2020.
- “Understanding Wholesale Power Market Designs and Their Benefits,” Infocast Southeast Renewable Energy Conference, November 19, 2020.
- “Building Support for Grid Transformation,” EUCI Workshop, August 18, 2020.
- “Recommendations on Resource-Specific Offer Caps March 2021 Capacity Auction for Commitment Period May 2022 to April 2023,” prepared for the Ontario Independent Electricity System Operator, coauthored with K. Spees, J. Pfeifenberger, and C. Haley, March 4, 2020.
- “Analysis of TRCA Surplus Allocation Methodology,” prepared for the Ontario Independent Electricity System Operator, coauthored with S. Ledgerwood, E. Shorin, and J. Higham, October 4, 2019.
- “Renewable Energy Development and IT Sector Load Growth,” Law Seminars International Electric Power in the Southwest Conference, July 15, 2019.
- “Potential Benefits of a Regional Wholesale Power Market to North Carolina’s Electricity Customers,” commissioned by the North Carolina Clean Energy Business Alliance, Carolina Utility Customers Association, and Conservatives for Clean Energy – North Carolina, coauthored with J. Pfeifenberger and J. Chang, April, 2019.
- “SPP’s Proposed Ramp Product: Initial Recommendations for Maximizing the Benefits of a Ramping Product,” presented to SPP’s Holistic Integrated Tariff Team, coauthored with J. Pfeifenberger, J. Chang, and K. Spees, September 11, 2018, and October 23, 2018.
- “Initial Comments on SPP’s Draft Ramp Product Report,” prepared for Golden Spread Electric Cooperative, Inc. (with J. Pfeifenberger, J. Chang, and K. Spees), August 30, 2018.

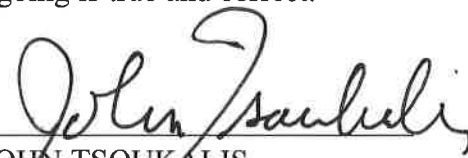
- “Framework-Based Approach to Building an Effective Trade Surveillance System and Compliance Program,” EUCI Financial Transmission and Auction Revenue Rights Conference, January 31, 2018.
- “Trade Surveillance Should Not Deter Traders,” coauthored with Shaun Ledgerwood, December 27, 2017, published by *Risk.net*.
- “Building an Effective Trade Surveillance System: A Framework-Based Approach using Guidance from Two Recent FERC White Papers,” coauthored with S. Ledgerwood, March 20, 2017, published by *The Brattle Group*.
- “Production Cost Savings Offered by Regional Transmission and a Regional Market in the Mountain West Transmission Group Footprint,” prepared for Basin Electric Power Cooperative, Black Hills Corporation, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Cooperative, and Western Area Power Administration (with J. Chang and J. Pfeifenger), December 1, 2016.
- “FERC’s Market Manipulation Rule: Impact on FTRs and the Virtual Market,” Energy Bar Association Midwest Chapter Annual Meeting, March 8, 2016.
- “The Critical Role of Transmission in Clean Power Plan Compliance,” Kinetic Conference for Competitive Bidding for Transmission Expansion, November 17, 2015.
- “Investment Trends and Fundamentals in U.S. Transmission and Electricity Infrastructure,” JP Morgan Investor Conference, July 17, 2015.
- “Market Manipulation Push is Widening the Compliance Gap,” coauthored with S. Ledgerwood, January 23 2015, *published on Risk.net*
- “Dynamics and Opportunities in Transmission Development,” TransForum East (Washington DC), December 2, 2014.
- “The Power of Dynamic Pricing,” coauthored with Ahmad Faruqui and Ryan Hledik, *The Electricity Journal*, April 2009, pp. 42-56.

AFFIRMATION

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

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

Date: May 31, 2024


JOHN TSOUKALIS

KILEY MOORE

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05____

Prepared Direct Testimony of

Kiley Moore

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

A. My name is Kiley Moore. My business address is 6100 Neil Road, Reno Nevada 89511. My present position is Director of Transmission Policy and Business Services 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, "NV Energy" or the "Companies").

2. **Q. WHAT ARE YOUR RESPONSIBILITIES AS THE DIRECTOR OF
TRANSMISSION POLICY AND BUSINESS SERVICES?**

A. I am responsible for administration of the Companies' FERC-approved Open Access Transmission Tariff ("OATT") including oversight of customer generator interconnection requests and transmission service requests. I also provide support on transmission policy with respect to NV Energy's participation in organized markets.

3. **Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL
EXPERIENCE.**

1 A. I have worked for NV Energy for approximately 17 years, spending the majority
2 of my career in various roles in transmission business services. I have led all FERC
3 proceedings involving NV Energy's OATT policy development and tariff
4 modifications. I have managed the generator interconnection process, assisted
5 transmission customers obtaining transmission service, including many of the
6 704B applicants, and overseen the associated transmission billing.

7
8 My Statement of Qualifications is attached as **Exhibit Moore-Direct 1** to this
9 testimony. I have previously testified before the Public Utilities Commission of
10 Nevada including in Docket No. 22-09006, the Companies' Third Amendment to
11 the 2021 Joint Integrated Resources Plan.

12
13 **4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

14 A. My testimony explains how the continued development of the Greenlink West and
15 Greenlink North projects is consistent with the Companies' obligation under the
16 OATT to expand its transmission system in response to the existing transmission
17 and interconnection service requests. I also discuss FERC's policy with respect to
18 cost allocation of network upgrades.

19
20 **5. Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

21 A. The Greenlink lines support the Companies' projected resource needs and satisfy
22 obligations under the OATT. In approving Greenlink West, the Commission
23 specifically recognized, "NV Energy is obligated to serve its native load and is also
24 obligated to serve and plan for network-only customers on a basis comparable to
25 delivery of its own generating and purchasing customers."¹ The Commission

26
27 ¹ March 21, 2021, Order in Docket No. 20-07023 at 433.

1 further found “that transmission is a key to meeting Nevada’s renewable energy
2 and carbon reduction goals” and that “these goals cannot be achieved without
3 opening up the State such that renewable energy resources can be accessed from
4 all areas of the State and out of state – and that can only be accomplished by
5 expanding the existing transmission system.”² The construction of Greenlink
6 North was authorized with the acceptance of the stipulation in Docket No. 21-
7 06001.³

8
9 These Commission’s findings with respect to the need for the Greenlink projects
10 and Companies’ obligations to its OATT customers are as relevant today as when
11 issued. NV Energy continues to have no Available Transfer Capability (“ATC”)
12 into the northern Nevada transmission system or over One Nevada Transmission
13 Line (“ON Line”). NV Energy has 681 megawatts (“MW”) of Network Integration
14 Transmission Service (“NITS”) requests and 125 MW of Point-to-Point
15 transmission requests dependent on Greenlink West. Additionally, the Companies
16 have 141 pending interconnection requests totaling approximately 54 gigawatts
17 (“GW”) for which Greenlink West, Greenlink North or both projects are contingent
18 facilities.

19
20 To satisfy these transmission requests, NV Energy has an affirmative duty under
21 the OATT to proceed with these vital transmission expansions. For NITS
22 customers, Section 28.2 of the OATT requires the Companies, to “plan, construct,
23 operate and maintain its Transmission System in accordance with Good Utility
24 Practice and its planning obligations in Attachment K in order to provide the

25
26 ² *Id.* at 302.

27 ³ *Joint Application for approval of NV Energy’s 2022-2041 Triennial Integrated Resource Plan, including the
28 Transmission Infrastructure for a Clean Energy Economy Plan, and 2022-2024 Energy Supply Plan*, January 24, 2022,
Order.

Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System." As to Point-to-Point transmission service, Section 19.6 of NV Energy's OATT states, "The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time." Similarly, Section 5.1.1 of OATT Attachment N, Large Generator Interconnection Procedures, mandates that NV Energy proceed to construct transmission network upgrades needed for new generator interconnection requests using reasonable efforts to meet the identified construction milestone dates.

FERC has specific transmission pricing and cost allocation policies associated with OATT transmission and interconnection service. FERC recognizes that integrated network transmission facilities benefit all transmission customers and warrant rolled-in rate treatment⁴. The Greenlink projects will be integrated elements of the Companies' high voltage transmission network. Further, they will address the needs of both native load and third-party OATT customers and have been long-standing components of NV Energy's transmission plans. Accordingly, Greenlink West and Greenlink North costs are properly recovered through general transmission charges, or rolled-in rates, and do not qualify for incremental cost allocation to specific customers under FERC's pricing policies.⁵

⁴ See, e.g., *Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at PP 65, 694 (2003) ("Order No. 2003"), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 (2004) ("Order No. 2003-A"), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004) ("Order No. 2003-B"), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,410 (2005) (Order No. 2003-C")

⁵ See, e.g., *New Eng. Power Pool*, 83 FERC ¶ 61,045 at 61,235 (1998). See also *Pa. Elec. Co.*, 58 FERC ¶ 61,278 (1992).

COMPLIANCE WITH FERC REQUIREMENTS

6. Q. CAN YOU PROVIDE SOME BACKGROUND ON THE CREATION OF NV ENERGY’S OATT?

A. In 1996, FERC issued a landmark order (FERC Order 888)⁶. FERC required that transmission providers offer third parties “open access” to their transmission systems under a pro forma OATT with standardized rates, terms, conditions, processes, and contracts Any deviations from the pro forma OATT must be filed with FERC for approval, and the transmission provider must demonstrate that the deviation is “consistent with or superior to” the procedures adopted by FERC⁷.

Originally, Sierra and Nevada Power had separate OATTs. In the 1999 proceeding in which FERC approved the business combination of Nevada Power and Sierra, FERC also approved the utilities’ usage of a combined OATT⁸. Currently, NV Energy requested in Docket No. ER15-179-000 that FERC authorize the relocation of the joint tariff assigned to NV Energy, Inc. from the NV Energy tariff database to a newly-created Nevada Power tariff database. Sierra Pacific Power submitted a standing concurrence to the OATT in the new tariff database in Docket No. ER15-182-000. On December 15, 2014, FERC’s Office of Energy Market Regulation accepted the relocation of the NV Energy OATT to the Nevada Power

⁶ *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh’g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh’g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh’g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff’d in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff’d sub nom. New York v. FERC*, 535 U.S. 1 (2002).

⁷ Standardization of Generator Interconnection Agreements and Procedures, 104 FERC ¶ 61,103 (2003) (“Order No. 2003”). *Order on reh’g*, Order No. 2003-A, 106 FERC ¶ 61,220, *Order on reh’g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *Order on reh’g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005).

⁸ *Sierra Pacific Power Company and Nevada Power Company*, 87 FERC ¶ 61,077 (1999).

tariff database, effective November 1, 2014. Since that time, Nevada Power administers the Companies' joint OATT.

7. Q. WHAT SERVICES DOES THE FEDERAL OATT GOVERN?

A. The OATT primarily governs two basic services: transmission service and generator interconnection. Transmission service products include: (1) Network Integration Transmission Service ("NITS") and (2) Point-to-Point Transmission Service which is further delineated by the service request term. Long-term Point-to-Point Transmission Service has a term over one year and must be procured on a firm basis. Requests with a term over five years are subject to rollover rights allowing the customer to continue their request in perpetuity. NV Energy must honor rollover rights into account in the Companies' transmission planning process. Short-term Point-to-Point Transmission Service has a term under one year. A customer can request short-term Point-to-Point Service as either a firm or non-firm product. The difference between firm transmission service and non-firm transmission service is the curtailment priority. Non-firm transmission service will be curtailed prior to firm transmission service in the event of any outages or contingencies on the transmission system. If the service request is for firm service, NV Energy must determine if the request can be accommodated with ATC. Absent ATC, NV Energy is obligated to expand its transmission system to meet the requested customer need.

NITS "allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the [NV Energy] utilizes its Transmission

System to serve its Native Load Customers.”⁹ Each NITS customer must execute a Network Integration Transmission Service agreement that details their resources and how they intend to deliver these resources to their load. The NITS customer must also execute a transmission reduction plan and a network operating agreement, which requires the NITS customer to provide an annual 10-year forward looking load forecast. NV Energy uses the 10-year load forecast to inform its transmission plan. The NITS customer’s load and resource dispatch needs are treated similarly to NV Energy’s native load forecasts and service plans. NV Energy is required under the OATT to expand its transmission system to accommodate third-party NITS customer’s load growth in a comparable manner as it does for native load.

There are two forms of generator interconnection service: (1) energy resource interconnection service (“ERIS”) and (2) network resource interconnection service (“NRIS”). Energy resource interconnection service only allows the customer to deliver energy to the transmission system on an “as available basis.” Network resource interconnection service is a higher quality product that allows the interconnection customer to integrate its facility “in a manner comparable to that in which the [NV Energy] integrates its generating facilities to serve native load customers as designated Network Resources”¹⁰

8. Q. WHAT HAPPENS AFTER NV ENERGY RECEIVES A REQUEST FOR OATT SERVICE?

A. The OATT governs how NV Energy processes transmission service or generator interconnection requests. For transmission service, NV Energy determines whether

⁹ See the NV Energy OATT Part III Preamble.

¹⁰ NV Energy OATT at Attachment N, section 1.

1 there is ATC to grant the request or if a study is required to determine the necessary
2 upgrades. There are two studies that may be performed for transmission service.
3 A System Impact Study identifies any system constraints with specificity by
4 transmission element or flowgate, identifies redispatch options and conditional
5 curtailment options (when requested by an Eligible Customer), and identifies any
6 Direct Assignment Facilities or Network Upgrades required to provide the
7 requested service.

8
9 If any Direct Assignment Facilities or Network Upgrades are required, NV Energy
10 performs a Facilities Study to identify: the cost of Direct Assignment Facilities to
11 be charged to the Transmission Customer, the Transmission Customer's share of
12 the cost of any required Network Upgrades, and the time required to complete such
13 construction of the Direct Assignment Facilities and Network Upgrades. Once the
14 studies have been completed, the customer is tendered a Transmission Service
15 Agreement ("TSA") for execution. The TSA will outline all terms and conditions
16 required for the transmission service. If the transmission service customer executes
17 the TSA (either Point-to-Point or NITS), the transmission customer is confirming
18 and agreeing to take and pay for the requested service.

19
20 For generator interconnections, the OATT has Large Generator Interconnection
21 Procedures (for generators over 20 MW) and Small Generator Interconnection
22 Procedures (for generators under 20 MW). Both processes are very similar, with a
23 small distinction on differences of timing for the required studies for a small
24 generator. For purposes of this testimony, I will reference the process for a large
25 generator as NV Energy receives very few small generator interconnection
26 requests. NV Energy has a cluster study process, and generator interconnection
27

requests must be received during designated cluster study windows. Once a request has been received during the cluster and all deficiencies in the request have been cured, a cluster study is initiated.

Similar to transmission service, there are two studies: a System Impact Study and Facilities Study. The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Interconnection System Impact Study will provide a list of facilities that are required as a result of the interconnection of the proposed generator, a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct. The Interconnection Facilities Study will specify and estimate the cost of the equipment, engineering, procurement and construction work needed for the requested interconnection service. Once the studies have been completed, the interconnection customer will be tendered a Large Generator Interconnection Agreement (“LGIA”) for execution.

For both transmission service and generator interconnections, NV Energy is obligated to construct the required facilities and network upgrades to provide the open access to NV Energy’s transmission system.

9. Q. WHAT DO YOU MEAN BY “COST AND TIMING REQUIREMENTS” ASSOCIATED WITH PROVIDING THE REQUESTED OATT SERVICE?

A. When NV Energy receives a request for OATT service, it must evaluate whether it can reliably provide that service on its existing transmission system within the timeframe requested. For example, if the existing transmission system is capable of reliably delivering the requested amount of available transfer capacity

1 associated with a transmission service request or reliably interconnecting the
2 requested amount of generation associated with a generator interconnection
3 request, the OATT studies evaluating that request are likely to state that the service
4 can be granted within the requested timeframe with minimal or no transmission
5 system upgrade costs.

6
7 If, on the other hand, the existing transmission system is not capable of reliably
8 delivering or reliably interconnecting additional capacity in the area of the system
9 where the OATT service has been requested, NV Energy cannot simply conclude
10 no service can be provided and reject the service request. Rather, the OATT
11 requires NV Energy to identify what transmission system upgrades are needed to
12 accommodate the request, as well as the estimated cost and timing associated with
13 constructing those upgrades. Those upgrades then become requirements identified
14 in the OATT customer's OATT contract (TSA or LGIA as described above).

15
16 **10. Q. DOES THE OATT REQUIRE NV ENERGY TO CONSTRUCT**
17 **TRANSMISSION SYSTEM UPGRADES NECESSARY TO GRANT OATT**
18 **SERVICE REQUESTS?**

19 A. Yes. In Order No. 888, FERC established its open access transmission policies to
20 prohibit public utilities from using their ownership of the transmission system to
21 unduly discriminate against third-party generators and transmission customers.
22 The OATT requires NV Energy to construct direct assignment facilities and
23 transmission system upgrades necessary to grant OATT requests for transmission
24 service and interconnection service.

11. Q. CAN YOU DESCRIBE THE OATT’S REQUIREMENT TO CONSTRUCT TRANSMISSION SYSTEM UPGRADES IN RESPONSE TO A NITS REQUEST?

A. The OATT’s NITS provisions require a transmission provider to “plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider’s Transmission System” and “endeavor to construct and place into service sufficient transfer capability” to deliver network customer resources to load.¹¹

12. Q. CAN YOU DESCRIBE THE OATT’S REQUIREMENT TO CONSTRUCT TRANSMISSION SYSTEM UPGRADES IN RESPONSE TO A POINT-TO-POINT TRANSMISSION SERVICE REQUEST?

A. The OATT’s Point-to-Point Transmission Service provisions require a transmission provider to “use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service” if the transmission provider cannot accommodate the request because of insufficient capability on its

¹¹ NV Energy OATT, Section 28.2 (emphasis added). The provision is as follows:

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

system.¹² In addition, Section 19.6 of NV Energy's OATT states, "The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time."

13. Q. CAN YOU DESCRIBE THE OATT'S REQUIREMENT TO CONSTRUCT TRANSMISSION SYSTEM UPGRADES IN RESPONSE TO A GENERATOR INTERCONNECTION SERVICE REQUEST?

A. Yes. Attachments N and O of NV Energy's OATT contain comprehensive rules for interconnecting new generators, including the identification and construction of new network upgrades if they are necessary to grant the request. Importantly, the OATT process does not give NV Energy any ability to refuse an interconnection request simply because it would require new network upgrades.

NV Energy must identify any required system improvements for the generator to interconnect to the transmission system. Section 5.1.1 of OATT Attachment N Large Generator Interconnection Procedures states,

Transmission Provider shall design, procure, and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider

¹² NV Energy OATT, Section 15.4 (emphasis added). Section 15.4(a) of the OATT states,

If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify."

Similar requirements are contained in NV Energy OATT, Section 13.5.

shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

Reasonable Efforts is defined in the OATT as "with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement or the Provisional Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests."

14. Q. IF THE OATT SERVICE IS CONTINGENT ON COMPLETION OF UPGRADES IDENTIFIED IN THE COMPANIES' TRANSMISSION PLAN, HOW IS THIS RELATIONSHIP REFLECTED IN THE SERVICE AGREEMENTS?

A. If NV Energy cannot provide requested OATT service until a component of the long-term transmission plan is completed, that requirement is noted in both the underlying study and final OATT agreements. With respect to interconnection requests, these necessary underlying upgrades are known as a "Contingent Facility":

Contingent Facilities shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for Re-Studies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing.¹³

¹³ NV Energy OATT, Large Generator Interconnection Procedures, definitions.

**INITIAL IDENTIFICATION OF THE NEED FOR GREENLINK WEST AND
GREENLINK NORTH**

**15. Q. HOW DO THESE OATT OBLIGATIONS TO CONSTRUCT
TRANSMISSION SYSTEM UPGRADES RELATE TO THE GREENLINK
FACILITIES?**

A. The Greenlink facilities have been long-standing elements of the Companies' transmission and interconnection plans. With regard to interconnection requests, Greenlink West was first identified as a contingent facility in 2018 and Greenlink North was first identified as a contingent facility in 2020. Currently, 141 interconnection requests identify Greenlink as a contingent facility. With respect to transmission requests, Greenlink West was first identified as a necessary facility in 2018 with a request from Liberty to become a network integration transmission service customer, when it was identified that NV Energy had no ability to provide firm imports into the northern Nevada system. Thus, for almost six years and counting, NV Energy has been unable to grant any further transmission service requests that require firm import capability to serve load growth in northern Nevada. This situation has resulted in a queue for a backlog of northern Nevada import requests.

**THE COMMISSION'S PRIOR RECOGNITION OF GREENLINK'S
IMPORTANCE TO MEET CUSTOMER NEEDS**

**16. Q. HAS THE COMMISSION PREVIOUSLY DISCUSSED THE
IMPORTANCE OF GREENLINK?**

A. Yes. On March 22, 2021, the Commission issued an order approving the permitting, design, land acquisition, and construction of Greenlink West and the two collector stations, and two of the three 345 kV common ties.¹⁴ The March 2021 Order also approved the conceptual design, permitting, and land acquisition—but not construction – of Greenlink North.

17. Q. WHAT WERE THE COMMISSION’S FINDINGS WITH RESPECT TO GREENLINK?

A. The Commission has recognized the importance of the Greenlink lines to accommodate load growth, provide for new service into northern Nevada, access renewable generation in the state, and enhance the reliability and redundancy of NV Energy’s transmission system. Statements in the March 21, 2021, Order identified the following:

- “GL-W solves the immediate concerns of import capacity and also increases system reliability by creating a second transmission connection between northern and southern Nevada resulting in redundant transmission paths between the two systems and eliminating the single contingency of ON Line.”¹⁵
- “The GL-W project would provide benefits to SPPC and NPC and would open the renewable energy zones and resources located on the western side of the State.”¹⁶
- “The Commission finds that permitting certain portions of GL-N and constructing GL-W are essential for the development of renewables in Nevada.”¹⁷

¹⁴ Docket No. 20-07023.

¹⁵ March 21, 2021, Order at 4.

¹⁶ *Id.* at 303.

¹⁷ *Id.* at 306.

- “The Commission finds that there is a need over the next several years to begin planning and constructing the necessary resources to increase the existing 1,275 megawatts (“MW”) of import capability of the northern transmission system.”¹⁸
- “NV Energy is obligated to serve its native load and is also obligated to serve and plan for network-only customers on a basis comparable to delivery of its own generating and purchasing customers.”¹⁹
- “GL-W solves the immediate concerns of import capacity, increases system reliability by creating a second transmission connection between northern and southern Nevada resulting in redundant transmission paths between the two systems and eliminating the single contingency associated with loss of ON Line, and facilitates access to the BLM-defined Solar Energy Zones in Nevada: Armargosa Valley, Gold Point, and Millers;”²⁰ and
- “Transmission projects such as GL-W protect against extreme weather and other unexpected events.”²¹

18. Q. WERE THE FINDINGS BASED ON INFORMATION PROVIDED BY NV ENERGY WITH RESPECT TO TRANSMISSION AND INTERCONNECTION REQUESTS?

A. Yes. The March 2021 Order noted:

- NV Energy states that, based upon the information received from its transmission customers, it estimates that starting in 2022 to 2023, current transmission load forecasts will exceed the total 525 MW of available third-

¹⁸ *Id.* at 433.

¹⁹ *Id.* at 433.

²⁰ *Id.* at 435.

²¹ *Id.* at 447.

party capacity and its third-party reservations are expected to increase by more than 175 MW in the next decade.²²

- NV Energy further specified that nearly 246 MW of additional transmission import capacity is needed when taking into account both pending and denied transmission service requests and existing network customers and could further increase to nearly 400 MW if Nevada Gold Mines chooses to exit NV Energy's bundled retail service in 2020.²³

**NV ENERGY'S CURRENT NEED FOR GREENLINK WEST AND
GREENLINK NORTH**

**19. Q. HAS THE NEED FOR GREENLINK WEST AND GREENLINK NORTH
DIMINISHED SINCE THE COMMISSION'S ORDERS?**

A. Definitely not. NV Energy's transmission service and generator interconnection queues have seen an increased need for both Greenlink lines since the Commission authorized construction of Greenlink West and Greenlink North. Based on the current status of the transmission and interconnection queues as well as NV Energy's own native load needs, Greenlink West and Greenlink North are essential to continued service and fulfillment of the Companies' OATT requirements.

**20. Q. WHAT IS THE CURRENT STATUS OF THE INTERCONNECTION
QUEUE?**

A. NV Energy has approximately 40 GW of generator interconnection projects in its interconnection study queue and an additional 33 GW of generator interconnections that have signed contracts to construct their project. Thus, NV

²² *Id.* at 145.

²³ *Id.* at 145.

Energy has approximately 73 GW of total queued generation, of which 54 GW of generation require the Greenlink projects to reliably interconnect the generation and manage the transmission system.

NV Energy currently has 105 generator interconnections that require the construction of both Greenlink West and Greenlink North for their interconnection. When NV Energy opened its Greenlink Interconnection Cluster on December 1, 2022, the Companies received 57 generator interconnection requests to interconnect directly to either Greenlink West or Greenlink North. 54 of these 57 generators are included in the 105 total that requires both lines. In addition to the 105 generators that require both Greenlink West and Greenlink North, there are 35 projects that require only Greenlink West be constructed and one project that requires only Greenlink North. Thus, the Companies received 141 interconnection requests in total for which the Greenlink projects are contingent facilities. The generator interconnection queue only continues to grow intensifying the need of the Greenlink West and Greenlink North transmission lines.

21. Q. HAVE YOU EXECUTED INTERCONNECTION AGREEMENTS IDENTIFYING GREENLINK WEST AND GREENLINK NORTH AS CONTINGENT FACILITIES?

A. Yes. Of the 141 projects that call out the need for Greenlink West, Greenlink North, or both, there are 67 projects that have executed interconnection agreements. The counterparties to these executed agreements have, in total, secured contractual rights to all of the estimated 23,199 MW of interconnection capability of the Greenlink lines. Of the 67 executed interconnection agreements, there are 26 projects accounting for 8,614 MW that are currently active and in good standing.

Under the Large Generator interconnection procedures, generators can suspend work on their interconnection request for up to three years.²⁴ At the end of the suspension period, the generator must recommence development activities or withdraw from the interconnection process. Currently, 41 generators accounting for 14,585 MW are in suspension.

22. Q. WHY HAS GREENLINK WEST AND GREENLINK NORTH BEEN IDENTIFIED AS A CONTINGENT FACILITY FOR THE 141 GENERATOR INTERCONNECTIONS?

A. The study cases for the interconnection projects were based on the requested and likely In-Service Dates. These included the anticipated completion dates for Greenlink West and Greenlink North. Due to the size and number of generator interconnections, if the Greenlink lines were not included initially in the base case, similar projects would have to have been identified in order to move power from North to South or South to North to sync the generation to load. In order to perform the interconnection studies, NV Energy turned down NV Energy's thermal units throughout the system to replace their generation with the interconnection customers' generation. This helps identify whether the system is able to sync the generation to load and identifies upgrades required to maintain reliability.

23. Q. CAN YOU DESCRIBE THE SIMULTANEOUS IMPORT CAPACITY LIMITATIONS IN NORTHERN NEVADA?

A. Northern Nevada has several interchange transmission lines that provide the ability to import into the northern Nevada transmission system. The simultaneous northern Nevada import capacity includes a NERC N-1 contingency rating that

²⁴ See the Standard Large Generator Interconnection Procedures in Attachment N of NV Energy's OATT at section 5.16.

decreases the amount of capacity available for import into northern Nevada based on detailed power flow analysis. This power flow analysis was completed using various operating assumptions and WECC base cases and identified any critical contingencies on the system that would limit overall simultaneous import. The simultaneous northern Nevada import capacity takes into account what reduction to ATC would need to occur in order to maintain the reliability of the transmission system and not incur overloads or voltage deviations due to the loss of critical transmission facilities. The loss of the Robinson Summit – Falcon 345 kV line has been identified as the most limiting contingency in the northern Nevada maximum import case. Accordingly, the northern Nevada simultaneous import capacity is currently rated at 1,275 MW. With the addition of Greenlink West, the Northern Nevada simultaneous import capacity will increase to 2,000 MW. With the addition of Greenlink North, the northern Nevada simultaneous import capacity will increase to 2,800 MW.

Of the current 1,275 MW for import into Northern Nevada, NV Energy is currently oversubscribed. NV Energy native load utilizes all 600 MW of the south-to-north transmission capacity over ON Line. Additionally, 175 MW of the 1,275 MW limitation is held as Transmission Reliability Margin to meet the obligations under the Western Power Pool Reserve Sharing Agreement. The remaining 500 MW of import capacity is already reserved by existing network and point-to-point customers.

24. Q. WHAT IS THE CURRENT STATUS OF THE TRANSMISSION SERVICE QUEUE?

1 A. The Greenlink West and Greenlink North lines are vital to support existing
2 transmission requests and third-party load growth for wholesale transmission
3 customers in Northern Nevada. NV Energy's Transmission Service queue should
4 be thought of as supporting two different types of requests: (1) those that require
5 import capacity into northern Nevada and (2) those that require capacity across NV
6 Energy's transmission system.

7
8 During the October 2022 Greenlink Transmission Capacity and Allocation study,
9 NV Energy determined that, of the additional 725 MW of simultaneous Northern
10 Nevada import capacity that Greenlink West added, a total of 681 MW needed to
11 be allocated to NV Energy's network customers to fulfill pre-existing obligations
12 to plan for NV Energy customers load growth pursuant to the OATT. This amount
13 consisted of:

- 14 • An existing oversubscription of 66 MW for service into northern Nevada.
- 15 • 420 MW in the current queue for transmission service requests that NV
- 16 Energy has been unable to grant for import into Northern Nevada; and
- 17 • 195 MW to meet projected load growth as reflected in NV Energy's NITS
- 18 customers 10-year load forecasts.

19 Even though the Plexos modeling of the Companies' south-north energy supply
20 portfolios demonstrated a native load need of 623 MW by 2027, NV Energy
21 transmission could only grant 44 MW based on the 725 MW total increase to the
22 northern Nevada simultaneous import limit from Greenlink West.

23
24 With the completion of Greenlink North and the additional 800 MW in import
25 capacity into Northern Nevada, NV Energy's native load will be allocated the 579
26 MW shortfall existing from the 2027 projection.

By 2032, NV Energy will receive for service to native load customers an additional northern Nevada import of 221 MW bringing the total allocation of additional Greenlink transfer capacity to 844 MW. NV Energy will be granted on behalf of native load customers the full 915 MW for South-North transfers.

In addition to the network customers' load growth and new requests, NV Energy has seven executed Point-to-Point transmission service agreements totaling 125 MW that would require capacity across Greenlink West in the north-to-south direction. Five of these Point-to-Point transmission service requests originally had requested service commensurate with the originally proposed Greenlink West in-service date of January 1, 2027. Based on the current project completion estimates, NV Energy will provide the transmission customers with counteroffers to commence the first day of the month following completion of Greenlink West. These seven requests are greater than five years in duration. Accordingly, NV Energy will have to plan to accommodate rollover rights. NV Energy has two additional Point-to-Point transmission service requests totaling 54 MW that have been granted with the capacity from Greenlink West; however, their rollover rights have been restricted due to the prior-in-time capacity allocation to native load once Greenlink North has been constructed.

25. Q. WHAT WOULD IT MEAN FOR FERC-JURISDICTIONAL SERVICE REQUESTS WITH EXECUTED CONTRACTS IF THE GREENLINK LINES ARE NOT CONSTRUCTED?

A. I cannot speak to the legal implications of the failure to construct Greenlink West and Greenlink North. I can, however, say that NV Energy, in good faith, acted consistently with the federal OATT process and obligations when it identified the

Greenlink West and Greenlink North as transmission system upgrades that must be constructed to reliably provide the requested service. NV Energy also acted consistently with the federal OATT process when it listed Greenlink West and Greenlink North as contingent facilities in the executed contracts. If NV Energy is put in a position where it cannot construct these specific lines, NV Energy would still be under a federal obligation to expand its transmission system to accommodate FERC-jurisdictional requests for OATT service.

FERC TRANSMISSION COST-ALLOCATION POLICIES

26. Q. WILL THE COST OF GREENLINK NEVADA BE INCLUDED IN NV ENERGY'S OATT TRANSMISSION RATES?

A. Yes. Greenlink West and Greenlink North are considered integrated network transmission assets under NV Energy's OATT. As a result, FERC precedent for ratemaking requires NV Energy to roll the costs of these assets into NV Energy's transmission rate base. As the Commission has recognized, FERC has "exclusive jurisdiction" over the transmission of electric energy in interstate commerce and that "FERC's authority extends to the federal allocation of transmission costs."²⁵

27. Q. HOW WILL THE COSTS OF THE GREENLINK FACILITIES BE REFLECTED IN NV ENERGY'S OATT TRANSMISSION RATES AND WHO WILL PAY THESE RATES?

A. NV Energy will include the cost of the Greenlink projects in the transmission revenue requirement for service under the OATT. FERC evaluates cost and benefits of NV Energy's system on an integrated, single system basis when setting

²⁵ Docket No. 20-07023, March 2021, 2021, Order at 594.

just and reasonable transmission rates, realizing that all customers benefit from the Companies' system at different times and in different ways.

28. **Q. DOES FERC REQUIRE THAT ROLLED-IN RATES BE UTILIZED?**

A. There are two payment options available for transmission service under the OATT: (1) a rolled-in rate or (2) an incremental rate. By far the most common is a rolled-in rate that allows for the costs of new projects to be recovered through the regular transmission charges. Under an incremental rate, the customer does not pay the standard transmission access charge based on the average system rate; rather they pay a rate associated with only the costs of the upgrades needed to grant them service. FERC permits the transmission provider to charge a customer the "higher of" the rolled-in rate or an incremental rate but not both.²⁶

FERC, however, will only allow the incremental rate to be assessed for the costs associated with grid expansion that are required solely to accommodate a new or expanded transmission service request.²⁷ Since Greenlink West and Greenlink North are longstanding, critical components of NV Energy's long-term transmission plan, and are required for native load service as well as for numerous existing transmission and interconnection requests, these facilities cannot be deemed "but for" a particular transmission customer associated with an incremental rate application. Accordingly, the Greenlink facilities must be rolled into NV Energy's transmission rates in accordance with FERC's transmission pricing policy.

²⁶ *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, FERC Stats. & Regs. ¶ 31,005 (1994).

²⁷ *New Eng. Power Pool*, 83 FERC ¶ 61,045 at 61,235 (1998). See also *Pa. Elec. Co.*, 58 FERC ¶ 61,278 (1992).

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RECOMMENDATION AND CONCLUSION

29. Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. I recommend that the Commission continue its support for the development of the Greenling West, Greenlink North and related upgrades. As recognized by the Commission, these projects are vital to the development of the state and achieving its renewable goals. My testimony demonstrates that these projects also enable the Companies to meet their obligation under the OATT to provide for the needs of third-party transmission and interconnection customers.

30. Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT MOORE-DIRECT-1

STATEMENT OF QUALIFICATIONS
KILEY L MOORE
NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANIES d/b/a NV Energy
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137

PROFESSIONAL EXPERIENCE

NV ENERGY – April 2022 to Present

Director – Transmission Policy and Business Services

- Monitor and participate Federal Energy Regulatory Commission's proposed rule makings on the Company's behalf
- Manage the Company's implementation of the Federal Energy Regulatory Commission regulations under the Open Access Transmission Tariff (OATT)
- Lead a staff who manages all generator interconnection requests and transmission service requests under the OATT

Director – Regional Transmission and Market Development

- Analyze prospective day ahead markets, provide guidance into the development of western markets for NV Energy's customers benefit.
- Collaborate with other utilities on regional needs for transmission and transmission expansion efforts and cost sharing benefits.

ORMAT TECHNOLOGIES INC – January 2021 to April 2022

Director—Geothermal Origination

- Originated long-term revenue contracts for Ormat's geothermal pipeline in North America.
- Led Ormat's transmission strategy by identifying and securing available transmission service for deliverability and pursue discussions regarding partnership opportunities and/or transmission acquisition.
- Managed Ormat's generator interconnection and transmission pipeline.

NV ENERGY – June 2006 to December 2020

Manager – Transmission Business Services

- Oversight of the Transmission Business Services team including the generator interconnection and transmission services queues, Open Access Same Time Information System, and transmission billing.
- Managed NV Energy's Open Access Transmission Tariff including compliance.
- Developed and implemented of Federal Energy Regulatory Commission orders and policy into workable business practices and Tariff language.

Project Manager—Transmission Business Services

- Lead a technical and construction team for successful metering and telecom installations associated with NV Energy's retail access network customers unbundling services under Nevada Revised Statute 704B.
- Engaged stakeholders and developed NV Energy's Energy Imbalance Market process for new participating and non-participating resources

Senior Consultant—Transmission

Consultant—Transmission

Contracts Agent—Business Development, Transmission

Intern—Business Development, Transmission

- Managed the Interconnection and transmission service queues and contracts with respect to Federal Energy Regulatory Commission Regulations and the Company's Open Access Transmission Tariff timelines.
- Negotiated contracts with customers (e.g. Interconnection Agreements, Transmission Service Agreements, Network Operating Agreements, Network Transmission Service Agreements and Engineering and Procurement Agreements).

Utility Design Administrator—New Business

- Performed complete design work for basic electric and gas new construction or capital maintenance.

EDUCATION

University of Nevada, Reno

Master of Business Administration, 2011

University of Nevada, Reno

Bachelor of Science / Supply Chain Management and Marketing, 2007

AFFIRMATION

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

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

Date: May 31, 2024


KILEY MOORE

JOSH LANGDON

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

2024 Joint Triennial Integrated Resource Plan (2025-2044)
Docket No. 24-05 ____

Prepared Direct Testimony of

Josh Langdon

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

A. My name is Josh Langdon. My current position is Vice President, Transmission,
for Nevada Power Company d/b/a NV Energy (“Nevada Power”) and Sierra Pacific
Power Company d/b/a NV Energy (“Sierra” and, together with Nevada Power, the
“Companies”). My business address is 7155 S. Lindell Rd, Las Vegas, Nevada. I
am filing testimony on behalf of the Companies.

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

A. I have been employed by the Companies for over 15 years. I hold a Bachelor of
Science degree in Electrical Engineering and a Master of Business Administration
degree from the University of Nevada, Las Vegas. I am also a licensed Professional
Engineer in the State of Nevada. I joined the Companies in 2008 as an Engineer in
Energy Supply. Since that time, I have held several positions in the Companies,
including Power Generation engineering positions and various Generation
Operations and Maintenance roles prior to increasing leadership responsibility
within the Energy Supply team culminating as a Plant Director. In 2019, I

transferred to Energy Delivery as the Transmission Director of Grid Reliability and System Operations. Within this role, I was responsible for the Companies' Balancing Authority, Transmission and Distribution operating functions. In 2020, I was selected for my current role as Vice President of Transmission, where I am responsible for real time operations for the Companies' Balancing Authority area, substations, and telecommunication system operations. Beginning in January of 2024, my responsibilities expanded to include Greenlink development. My statement of qualifications is attached as **Exhibit Langdon-Direct-1**.

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

A. As the Vice President of Transmission, I am responsible for ensuring the safe, compliant, and reliable real-time operation of the Companies' telecommunication, substation, transmission, and distribution systems. Additionally, I am responsible for the Greenlink Transmission project development and execution.

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

A. Yes. Most recently, I supported the reasonableness and prudence of the Companies' project investments in critical substation physical security ballistic shield additions, which were included in the Nevada Power's 2023 general rate case. Additionally, most recently, I submitted pre-filed testimony associated with the application of the Companies to merge into a single corporate entity, Docket No. 22-03028.

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

A. My testimony supports the Companies' request for approval of the Greenlink Nevada Transmission project at the updated forecasted costs. The purpose of my testimony is to provide an overarching Greenlink Nevada Transmission project overview, which includes a summary of related key subject matter expert witness updates that support the need for the project at the updated cost forecast. Lastly, I will provide support and serve as the overall policy witness for the Companies' Greenlink Nevada Transmission project.

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

A. I am sponsoring the following Exhibit:

Langdon-Direct-1 – Statement of Qualifications

7. Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section I, I describe the current Greenlink Nevada Transmission project scope and in-service schedule. In section II, I introduce and summarize key subject matter expert witnesses supporting the key drivers for the project forecast increases, the need to construct the project at the increased forecast, and a request to approve the Greenlink Transmission project at the updated project cost forecasts.

I GREENLINK NEVADA TRANSMISSION PROJECT BACKGROUND

8. Q. PLEASE DESCRIBE THE MAJOR COMPONENTS OF THE GREENLINK NEVADA TRANSMISSION PROJECT?

A. The Greenlink Nevada Project includes two primary segments which encompass four main nodes. In addition to the transmission line, both segments require modifications to existing substations, the addition of new collector substations and

the addition of multiple telecommunications facilities needed for operations and protection of the transmission segments and substations. Altogether, the Greenlink Nevada project is not only vital for meeting Nevada's renewable energy and carbon reduction goals but also plays a crucial role in system reliability and the broader western U.S. energy market by improving the state's ability to export and import electricity and more effectively dispatch energy across the state.

SEGMENT	NODE
GREENLINK WEST	Greenlink West
	Common Tie
	Northwest to Harry Allen Tie
GREENLINK NORTH	Greenlink North

Greenlink West ("GLW")

9. Q. PLEASE DESCRIBE THE GREENLINK WEST NEVADA TRANSMISSION PROJECT.

A. Greenlink West ("GLW"), the first major segment, is approximately 325-miles of 525 kilovolt ("kV") transmission line from Las Vegas, Nevada, to Yerington, Nevada, creating a critical second path between the northern and southern Nevada's electric systems.

The GLW transmission line begins at Northwest Substation (Las Vegas), routes through several Bureau of Land Management-defined renewable energy zones, which are crucial for accessing untapped renewable resources in Nevada and terminates at Fort Churchill Substation (Yerington). The required rebuilding/expansion of these existing terminal substations is included within the project

scope. Also included in the GLW scope are the new Sagebrush, formally known as Amargosa, (Nye Country) and Esmeralda (Esmeralda County) 525/230 kV greenfield collector substations needed to accommodate renewable large generator interconnections.

GLW also includes common tie projects in Northern Nevada which are approximately 80 miles of 345 kV transmission lines to serve load in Reno and the Tahoe Reno Industrial Center. Included as part of the common ties are three transmission lines. Fort Churchill to Mira Loma substation and two transmission lines from Fort Churchill to Comstock Meadows. Since the original project proposal, the second Fort Churchill to Comstock Meadows line was added to the Greenlink Nevada Transmission project due to continued increase in load growth projections beyond the 2019 load forecasts.

Lastly, GLW also includes a separate 35-mile 525 kV transmission line connecting Northwest and Harry Allen substations in southern Nevada which completes the 525 kV transmission loop. The Harry Allen to Northwest 525 kV transmission line provides substantial benefits in terms of electrical system reliability and operational flexibility.

10. Q. WHAT IS THE CURRENT ANTICIPATED IN-SERVICE DATE FOR THE GREENLINK WEST SEGMENT?

A. Apart from the Harry Allen to Northwest segment, the GLW project, pending a June 2024 BLM record of decision and notice to proceed in December of 2024, is scheduled to be completed and in-serviced in May of 2027. The Harry Allen to

Northwest segment is scheduled to be completed and in-service in coordination with Greenlink North.

Greenlink North (“GLN”)

11. Q. PLEASE DESCRIBE THE GREENLINK NORTH NEVADA TRANSMISSION PROJECT.

A. Greenlink North (“GLN”), the second major segment, is approximately 235-mile, 525 kV line from Ely, Nevada, to Yerington, Nevada, and includes rebuilding/expansion of existing substations, and adding Lander Substation, a new greenfield 120 kV to 525 kV Substation. The GLN transmission line begins at Robinson Summit Substation (Ely), routes through several Bureau of Land Management-defined renewable energy zones, which are crucial for accessing untapped renewable resources in Nevada, and terminates at Fort Churchill substation (Yerington). Figure GL-1 illustrates the general location of both GLW and GLN.

FIGURE GL-1 GREENLINK PROJECT DIAGRAM



12. Q. WHAT ARE THE PRIMARY REASONS THE GREENLINK NEVADA PROJECT IS REQUIRED?

A. Subject matter experts summarized in Section II will provide greater details; however, I will highlight several requirements that the Greenlink Nevada project addresses.

First, the loss of the One Nevada (“ON”) 525 kV Transmission Line for both forced outages or scheduled maintenance limits NV Energy’s participation and customer benefits from the energy imbalance market and eliminates NV Energy’s ability to jointly dispatch resources as efficiently. As the only current transmission connection between northern and southern Nevada, there are operational conditions

1 where the largest most severe contingency to serving load is the loss of ON Line.
2 The Greenlink Nevada Project when fully completed loops the 525 kV system
3 across the state eliminating this single contingency.

4
5 Second, the northern Nevada service territory currently has no available
6 transmission capacity to serve our native load growth forecast or NERC required
7 Network Integrated Transmission service customers. Both Greenlink West and
8 North are required to meet both native and transmission load requirements. Without
9 increasing transmission import capacity, economic growth and development will
10 be further limited. Additionally, NERC requires the Companies to provide open
11 access to interconnect new supply resources. There are numerous interconnection
12 requests, some already with executed agreements, to interconnect to the Greenlink
13 Nevada project. In total, the interconnection requests at the three collector
14 substations exceed 20,000 megawatts (“MW”).

15
16 Third, the Greenlink Nevada Project creates a renewable energy highway that
17 allows for access to and transportation of renewable energy from Nevada’s
18 resource-rich renewable energy zones. The Greenlink Nevada project is critical to
19 advancing Nevada closer to a net-zero carbon future and continuing to meet
20 Nevada’s renewable portfolio standard requirement while also positioning Nevada
21 to diversify its renewable portfolio by creating access to affordable and more
22 diverse energy projects across the West.

23
24 Additionally, the Greenlink Nevada Project facilitates regional transmission
25 opportunities to further evaluate opportunities to diversify renewable energy
26 options for Nevada in the future.

II SUBJECT MATTER EXPERTS SUPPORTING GREENLINK NEVADA CONSTRUCTION

13. Q. PLEASE LIST AND SUMMARIZE THE COMPANIES' SUBJECT MATTER EXPERT WITNESS TESTIMONY SPONSORING GREENLINK REQUEST FOR CONTINUED APPROVAL AT THE CURRENT TOTAL COST FORECAST.

A. The sponsors and subject matter experts for each area are described below:

Ryan Atkins – Provides supporting Greenlink Nevada Transmission project justifications for continued approval of the project, despite the cost forecast increase, by highlighting system benefits, economic and environmental impacts, approval justifications and requests continued approval of the project cost forecast. Mr. Atkins also highlights alternative projects considered and demonstrates that none of the alternative provides the comprehensive benefits meeting system capacity, renewable energy access, and compliance with regulatory interconnection requirements.

Michael Behrens – Details how the Greenlink Nevada Transmission project forecasted cost increase impacts the Companies' revenue requirement as well as mitigations to reduce the net rate impacts on customers.

Shahzad Lateef – Provides an updated cost forecast for the Greenlink Nevada transmission project, highlighting project changes and cost escalations from the original estimate and what actions have been taken by NV Energy to prudently manage costs escalations. Mr. Lateef also details primary drivers for cost

1 escalations because of supply chain disruptions, historic inflation, workforce
2 shortages, and finally the Bureau of Land Management (“BLM”) permitting
3 process and its impact on project timelines and costs. Lastly, Mr. Lateef highlights
4 outstanding risks associated with future potential cost forecast changes, including
5 potential increases in commodity prices, labor costs, and further permitting delays.
6

7 **Kiley Moore** – Details the Open Access Transmission Tariff (“OATT”) obligations
8 to expand NV Energy’s transmission system to meet existing transmission and
9 interconnection service requests and how those costs are allocated in accordance
10 with Federal Energy Regulatory Commission (“FERC”) policy.
11

12 **Charles Pottey** – Details how the Greenlink Nevada Project is required to reduce
13 operational risk and meet transmission planning and compliance requirements with
14 mandatory reliability standards set by FERC, North American Electric Reliability
15 Corporation (NERC), and Western Electricity Coordinating Council (WECC). The
16 Greenlink projects help NV Energy meet these standards, particularly NERC's
17 TPL-001-5, which requires reliable service under various system contingencies.
18 Mr. Pottey also evaluates nine alternative transmission projects but concludes that
19 none provided the required transmission capacity and system benefits as effectively
20 as the Greenlink projects, justifying the need for the Greenlink Nevada
21 Transmission projects, highlighting their importance for meeting renewable energy
22 goals, ensuring system reliability, and complying with federal transmission
23 standards.
24
25
26
27

14. Q. PLEASE LIST AND SUMMARIZE THE EXTERNAL EXPERT
WITNESSES TESTIMONY SPONSORING GREENLINK REQUEST FOR
CONTINUED APPROVAL AT THE CURRENT TOTAL FORECAST?

A. John Tsoukalis, The Brattle Group – Details that despite project cost escalations, which are in line with industry standards and trends, the development of the Greenlink Nevada Transmission project delivers substantial benefits to Nevada. Mr. Tsoukalis conveys project benefits through economic savings associated with reduction in net power costs (reduced fuel and operating costs, decreased market power purchases, and increased off-system sales revenue), potential increased congestion revenues through a future western next-day market, reduction in renewable energy curtailments, and economic stimulus for Nevada communities. Mr. Tsoukalis also conveys operational benefits of the Greenlink Nevada project resulting in improved resilience, reliability, and resource adequacy risk while facilitating the load growth, future transmission service requests, and maintaining compliance with Nevada’s renewable portfolio standards.

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

A. Yes.

EXHIBIT LANGDON-DIRECT-1

STATEMENT OF QUALIFICATIONS

Joshua Langdon
Vice President, Transmission
NV Energy
7155 Lindell Rd
Las Vegas, Nevada 89118
(702) 402-6600

My name is Joshua Langdon. I am the Transmission Vice President for Sierra Pacific Power Company and Nevada Power Company ("Companies"). The Transmission business unit includes real-time operations and maintenance for the Telecommunication, Substation, Transmission and Distribution system for the Companies ensuring safe and reliable energy delivery. Additionally, the Transmission business unit includes development responsibilities for the Companies large transmission projects.

I graduated from the University of Nevada Las Vegas in December of 2007 with a Bachelor of Science degree in Electrical Engineering. I received a master's in business administration from University of Nevada Las Vegas in May of 2016. I am a licensed Professional Engineer in Nevada.

In January of 2008, I joined the Companies as an associate Electrical Engineer in Generation Engineering. I remained in the department for four years progressing to Sr. Engineer. In these roles, my primary responsibilities were to provide engineering, project management, construction management, and commissioning support for power generation electrical system upgrades and retrofit projects. Additionally, I provided reliability inspections, equipment testing, and outage restoration support for all the Companies' generating stations.

In August of 2012, I was selected as the Plant Engineering Manager for several Nevada Power generating stations. In this role, I supported daily engineering, operational, and maintenance functions while establishing long-term strategic planning and capital investments to ensure continued safe and reliable operations.

In December of 2015, I was selected as the Maintenance Manager for Nevada Power's Walter Higgins and Goodsprings Generating Stations. In this capacity, I was responsible for all plant maintenance, capital investments, engineering, and plant outage management to ensure continued safe and reliable operations.

In December of 2017, I was selected to be the Plant Director at Nevada Power's Nellis Solar and Las Vegas Generating Stations. Within this role, I was responsible for all requirements to ensure safe and reliable operations. Additionally, I focused on improving plant safety and reliability while optimizing plant operations to meet the growing demand for flexible operating conditions.

In January of 2019, I was selected as the Director of Grid Operations and Reliability. Within this role, I was responsible for the Companies' Balancing Authority, Transmission and Distribution operating functions.

In May of 2020, I was selected to my current role as the Vice President of Transmission where I am responsible for safe, reliable, and compliant real time operations of the Companies Telecommunication, Substation, Transmission, and Distributions systems. In January of 2024, Transmission expanded to include Greenlink Nevada transmission development.

AFFIRMATION

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

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

Date: May 31, 2024


JOSHUA LANGDON