BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Annual Deferred Energy Accounting Adjustment Application of the Electric Division of Sierra Pacific Power Company d/b/a NV Energy for the 12-month period ending December 31, 2023, reset the Temporary Renewable Energy Development Charge, reset all components of the Renewable Energy Program Rate, reset the Base Energy Efficiency Program Rates, reset the Base Energy Efficiency Implementation Rates, reset the Energy Efficiency Program Amortization Rate, reset the Energy Efficiency Implementation Amortization Rate, and reset the Expanded Solar Access Program rate.	**Docket No. 24-03___**

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TESTIMONY

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TESTIMONY

EUGENE T. MEEHAN

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

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Eugene T. Meehan

I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

1. Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Eugene T. Meehan. I am a Special Consultant affiliated with National Economic Research Associates, Inc. ("NERA" or "NERA Economic Consulting"), having retired from NERA as a Senior Vice President. My address is 7042 Powderhorn Ct., Park City, Utah, 84098. I have prepared direct testimony on behalf of Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company").

2. Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF NERA'S BUSINESS.

A. NERA is a firm of more than 500 professional economists located in offices throughout the United States, Europe, Australia, and Asia. NERA provides consulting advice in litigation and regulatory settings, as well as strategic and planning advice to clients in the energy, telecommunications, television and broadcasting, securities, transportation, health, and banking industries.

3. Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I have more than 40 years of experience consulting with electric and gas utilities. That work has involved examination and advice on many issues related to power markets, power contract design, competitive bidding, and contract evaluation. For the past 25 years, I have been extensively involved in advising clients on restructuring-related issues, including risk analysis, risk management, power plant and power contract valuation, and post-transition regulatory issues. For more than 30 years, I have advised governments, regulators, and utilities with respect to the acquisition of power from third parties. These assignments have involved the review of power contract offers made by competitive power marketers and owners of generation assets. Additionally, I have testified numerous times with respect to the prudence of utility planning and power procurement. **Exhibit Meehan-Direct-1** contains a more detailed statement of my qualifications.

4. Q. PLEASE SUMMARIZE YOUR EXPERIENCE WITH WESTERN POWER MARKETS.

A. In late 1999 and early 2000, I reviewed the Request for Proposal ("RFP") process and bid evaluations of Public Service Company of Colorado for more than 1,000 MW of power and testified before the Public Service Commission of Colorado. In late October 2000, I began working with Pacific Gas & Electric Company ("PG&E") to review market prices in California and also began supervising NERA's efforts with respect to providing testimony in several phases of the Federal Energy Regulatory Commission ("FERC") refund proceeding (Docket No. EL-00-95-031). In late 2001 and continuing through 2002, I testified before the FERC on behalf of PG&E regarding the benchmark analysis of the power contract that was a central element of PG&E's original plan of reorganization to emerge from bankruptcy. In connection with this assignment, I reviewed more than 100

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contracts for power that were entered into by entities in the western United States between May 1999 and July 2002. In 2010, I reviewed and made recommendations with respect to the long-term power procurement practices of a major California utility. In 2018, I testified on behalf of San Diego Gas & Electric Company ("SDG&E") in an arbitration proceeding in connection with a dispute concerning a power purchase agreement resulting from a recent RFP and provided deposition testimony on behalf of SDG&E in a court proceeding related to an earlier SDG&E RFP for new capacity. I have testified before the Public Utilities Commission of Nevada ("Commission") regarding the power purchasing practices of Sierra and Nevada Power Company d/b/a NV Energy ("Nevada Power" and, together with Sierra, the "Companies") in Commission Docket Nos. 02-11021, 03-1014, 03-11019, 04-1006, 04-11028, 05-12001, 06-01016, 06-12001, 06-12002, 07-01022, 08-02042, 08-02043, 09-02029, 09-02030, 10-03003, 10-03004, 11-03003, 11-03004, 12-03004, 12-03005, 13-03003, 13-03004, 14-02040, 14-02041, 15-02040, 15-02039, 16-03003, 16-03004, 17-03001, 17-03002, 18-03002, 18-03003, 19-03001, 19-03002, 20-02026, 20-02027, 21-03005, 21-03006, 22-03001, 22-03002, 23-03005, and 23-03006. Through these assignments, I am very familiar with recent market conditions in the western United States and in Nevada.

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

A. I examine the prudence of non-renewable power transactions for terms of less than three years made by Sierra for delivery during the 12-month period of January 1, 2023, through December 31, 2023 ("Deferral Period"). Sierra is seeking a determination that the costs of these transactions, which are reflected in the Company's deferred balances, were prudently incurred and are reasonable. Power transactions for terms of three years or more have been examined and pre-approved by the Commission. I also provide background concerning market developments and their impact on the Companies' capacity acquisition opportunities.

II. SUMMARY OF POWER TRANSACTIONS

6. Q. PLEASE DESCRIBE THE ELECTRICITY TRANSACTIONS MADE BY SIERRA FOR THE DEFERRAL PERIOD.

A. The Company's power procurement activities for the Deferral Period were guided by the three objectives stated in the Company's Energy Supply Plans ("ESPs"):[1]

- Minimizing the cost of purchased power;
- Minimizing retail price volatility; and
- Maximizing the reliability of supply.

To realize these objectives, Sierra constructs diversified portfolios of power products that may include owned generation, tolling agreements, options, forward energy and capacity purchases and sales, as well as spot purchases and sales. Sierra then actively manages this portfolio, entering into market transactions to optimize the use of the Company's existing generation assets and contract portfolios.

The power transactions that I examined for prudence include all transactions of electricity and risk management products made on behalf of customers for the Deferral Period that have terms of less than three years. The portfolio constructed and managed by Sierra includes purchases of capacity and associated energy made

[1] Pursuant to the Commission's regulations, the Company files ESPs and ESP updates with the Commission for review and approval. Copies of the relevant Commission-approved ESPs, ESP updates, and relevant stipulations are provided as Technical Appendix 3.

to close the open capacity position, real-time electricity purchases and sales, and day-ahead electricity purchases and sales.

It is convenient to categorize the transactions made in terms of the type of product and the timing of their execution relative to delivery. I therefore define the following categories of transactions, which I will discuss in detail below:

1. **Purchases of Capacity and Associated Energy Made to Close the Open Capacity Position** – Purchases made in advance of the summer season to cover an open capacity position during the summer months.
2. **Spot Market Transactions** – Day-ahead and real-time transactions including purchases required to be able to serve load, sales that were necessary to put the Company's supply portfolio in balance with the actual loads on the Company's system, and/or transactions used to optimize the Company's portfolio on a day-ahead and real-time basis. These also include transactions made through participation in the California Independent System Operator's ("CAISO's") Western Energy Imbalance Market ("EIM").

The power transactions entered into by Sierra for the Deferral Period for periods of less than three years can be classified into one of the above categories. I address the transactions made in each category in turn below. Before addressing the specific transactions, however, I provide an overview of the prudence standard against which those transactions must be evaluated.

III. DEFINITION OF PRUDENCE STANDARD AND APPLICATION TO INSTANT PROCEEDING

7. Q. PLEASE PROVIDE THE DEFINITION OF PRUDENCE THAT YOU USE TO ADDRESS SIERRA'S TRANSACTIONS IN THIS CASE.

A. The standard for what constitutes prudent managerial action is well established in regulatory practice. It is best characterized as whether the Company's actions are generally consistent with what a reasonable person would have done given the information reasonably available at the time. I quote below from this Commission's decision in Docket No. 02-11201:

> *Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time the decision had to be made.*[2]

It is important to realize that there is not one exclusive decision or alternative that is reasonable, and hence, there is not one exclusive decision or alternative that is prudent. Decisions that are different, even very different, can both be prudent.

8. Q. HOW DO YOU ASSESS THE PRUDENCE OF THE TRANSACTIONS AT ISSUE IN THIS PROCEEDING?

A. I have developed a series of questions that provide a framework for evaluating whether Sierra's transactions were reasonable and prudent. I answer these questions based on objective evidence that was available at the time the transactions were executed. The following questions encompass the issues relevant to the

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[2] Docket No. 02-11201, May 13, 2003, Order, page 10.

prudence of Sierra's power procurement strategy and its implementation and are the questions that I use to objectively evaluate prudence:

1. **Did Sierra appropriately close its open capacity position using available market purchases?**

   This question focuses on how Sierra filled its open capacity position. In reviewing this question, I examine the consistency of the purchases made by Sierra with respect to the approved ESP and ESP updates, and the capacity need of the Company.

2. **Did appropriately use the spot markets to balance and to optimize its loads and resources?**

   This question assesses the reasonableness of the strategy and execution with respect to Spot Market Transactions. In reviewing this question, I examine the strategy and procedures used with respect to spot purchases and the execution of transactions relative to the market.

These questions and resulting answers provide an objective means of determining if the Company's purchases were prudent, as these questions focus directly on the main issues:

- the reasonableness of the strategy for and execution of purchases made for capacity; and
- the reasonableness of the strategy for and execution of Spot Market Transactions.

This systematic exercise is an objective approach to assess prudence because these questions can mostly be examined using reliable extrinsic and objective evidence of market conditions and the regulatory environment known at the time the decisions to enter into these transactions were made.

IV. CONTEXT OF SIERRA'S 2023 OPERATING ENVIRONMENT

9. Q. PLEASE DESCRIBE THE MODE OF OPERATION IN 2023 WITH RESPECT TO THE COMPANIES' UNIT COMMITMENT, DISPATCH, AND MARKET PURCHASE AND SALE ACTIVITY.

A. The One Nevada transmission line ("ON Line") was energized at the start of 2014, and the load-serving operations of Sierra were combined with the load-serving operations of its affiliate Nevada Power. The commitment, economic dispatch, and market transacting activities (joint operation) of the Company and Nevada Power have long been supervised and conducted by the same personnel in the Companies' Resource Optimization department using the same procedures and tools applied to optimize each utility's resources to serve native load at the lowest possible costs. Before the ON Line was energized, however, the Companies did not have an electric interconnection and conducted the commitment, dispatch, and market transactions independently. With the advent of the ON Line, the Companies are electrically interconnected, and the capacity of the interconnection is large enough that, for all practical purposes, there are no short-term constraints that arise in the course of jointly committing and dispatching the resources of the two utilities to serve the combined native load at least cost. The Companies operate as a single Balancing Area Authority ("BAA"). The unit commitment and dispatch of the two utilities, as well as the interface with the market to buy and sell power, are now performed recognizing that the Companies are a single BAA with the objective being overall cost minimization of serving the Companies' combined native load. The mode of operation is that of an overall joint commitment and dispatch of Nevada Power and Sierra resources to meet combined load in the least cost manner subject to maintaining system security.

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10. Q. IS THE JOINT OPERATION OF THE COMPANIES CONDUCTED PURSUANT TO PROVISIONS APPROVED BY A REGULATORY AUTHORITY?

A. Yes. The Commission recognized and approved that the Companies would be jointly dispatched in its approval of the ON Line.[3] FERC approved the specific provisions for the joint operation of Nevada Power and Sierra, and those provisions are memorialized in the Commission and FERC-approved Joint Dispatch Agreement ("JDA"). The JDA provides that the resources of the two utilities will be jointly dispatched to meet the combined load of the Companies based on the optimization of overall system costs. Additionally, the JDA contains explicitly approved procedures for determining and allocating the savings arising from joint dispatch, for allocating purchases of less than one year in duration to each utility, and for sharing in the cost and margins of sales made from the combined resources of the Companies.

11. Q. DOES THE CONTINUED IMPLEMENTATION OF JOINT OPERATIONS DURING THE DEFERRAL PERIOD UNDER THE JDA AFFECT HOW YOU EXAMINE PRUDENCE?

A. Yes. The resources of the Company are dedicated to joint dispatch, and the objective is to minimize the combined operating costs (fuel, variable O&M, purchase costs, and sales margins) of the combined resources of Nevada Power and Sierra to reliably meet the combined native load obligations of the Companies in the least cost manner. Hence, to assess prudence, I examine whether the interactions with the market on a forward and spot basis were conducted to prudently minimize the combined fuel and net purchased power costs of the joint

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[3] *See* Docket No. 10-02009, July 30, 2010, Order at ¶ 416.

Nevada Power and Sierra system to meet joint native load obligations. With joint dispatch, prudence in optimizing generation resources through market purchases and sales can only be analyzed relative to the objective of minimizing combined costs. Individual utility costs are a function of a FERC-approved allocation methodology and are prudent so long as the combined costs of the Companies can be shown to be prudent, and the FERC-approved allocation methodology has been properly followed.

12. Q. HAVE YOU REVIEWED THE JDA, JOINT DISPATCH, AND FERC-APPROVED METHODS FOR ALLOCATING JOINT DISPATCH SAVINGS, THE ENERGY FROM AND COSTS OF POWER PURCHASES, AND SALES REVENUES AND MARGINS?

A. Yes. In the course of my research, I have reviewed the JDA and these methods. I will briefly describe at a high level how joint operations are conducted and allocations are made under the JDA.

- A joint unit commitment and dispatch of generation resources is conducted considering all resources under the control of the Companies. This joint commitment and dispatch effort seeks to reliably meet the combined native loads of the Companies at the lowest possible cost. This ensures that the overall costs of dispatch for all Nevada native load customers are minimized.
- On a day-ahead basis, the incremental and decremental costs of a series of 50 MW on-peak and off-peak increments and decrements relative to the combined native loads of the utilities are calculated. Power traders canvass the market and available broker/exchange quotes, identify purchase or sale opportunities that will lower the costs of serving the combined native load, and can execute forward or day-ahead trades when such opportunities are

identified. This further ensures that the overall costs of serving the loads of all Nevada customers are minimized through trading in the forward and day-ahead markets. Additionally, traders examine reliability needs and execute day-ahead purchases required to maintain reliability.

- On a real-time basis, power traders canvass the market and obtain information on the opportunity for hourly real-time purchases and sales. Such opportunities are analyzed using the dispatch model to determine if engaging in a real-time purchase or sale will lower the cost of serving the combined native load of the Companies. Real-time purchases or sales that reduce the costs of serving native load on a combined basis are transacted. The model is updated as each purchase or sale is transacted. This further ensures that the overall costs of serving the loads of all Nevada customers are minimized through trading in the real-time market. This position is, since December 1, 2015, enhanced by balancing activities in the EIM.
- The transacting of real-time purchases or sales completes the activities used to minimize the overall costs incurred to serve the loads of all Nevada native-load customers at the lowest possible cost. The remaining steps are allocation steps. My review of prudence encompasses the steps above. While I have observed that the FERC-approved allocation procedures have been followed, I am not testifying as to compliance with those allocation procedures.

I will discuss the remaining allocation steps at a very high level. Purchases made to reduce the joint native load costs are allocated between the Companies based on relative hourly load; the cost each company incurs to generate to provide energy for sales is tracked and compensated; the margin on sales is shared between the Companies based on relative hourly resources providing energy; the company that incurs energy costs above those it would have incurred on a native load basis is compensated for those incurred costs; and, the Companies share in the hourly savings from joint dispatch based on the relative hourly resources providing energy. The values are determined from models that quantify actually incurred costs under joint dispatch, actually incurred costs of providing non-native sale energy, and reconstructed estimated costs of meeting each company's native load on a stand-alone basis.

13. Q. WERE THERE ANY ENHANCEMENTS TO OPERATING METHODS THAT WERE CONTINUED DURING THE DEFERRAL PERIOD?

A. Yes. Beginning in December 2015, the Companies commenced operation in the EIM. This continued through 2023. In addition to Nevada, the EIM balances load and generation in significant portions of 10 western states and British Columbia. The major implication to the Companies of participation in the EIM is that CAISO directs increases or decreases in generation on a 15- and 5-minute interval basis within the hour. Over these intervals, the dispatch of the Companies' resources is coordinated with all generation in the EIM market to meet the overall load in the EIM market area in the least cost manner. This results in intra-hourly generation and load balancing that is more efficient than what is possible using the Companies' resources alone, and results in what are best viewed as additional spot purchases or sales that would not be possible absent the EIM.

14. Q. DO THE COMPANIES PLAN TO COVER OPEN CAPACITY POSITIONS ON A JOINT BASIS?

A. Yes. Open capacity positions are positions that are open after consideration of long-term resources approved in the Companies' joint integrated resource plans. While the Companies track open capacity positions for Nevada Power and Sierra, the positions are filled considering the combined need for capacity to close the combined open position. Since capacity purchases made to fill these open positions are less than one year in duration, the purchases are allocated through the JDA using a load responsibility share ratio.

V. MAINTAINING RELIABILITY IN THE CURRENT MARKET ENVIRONMENT

15. Q. WHAT FACTORS AFFECT THE COMPANIES' ABILITY TO RELIABLY SERVE LOAD AT THE LOWEST REASONABLE COSTS IN A PRUDENT MANNER?

A. Four primary factors affect the Companies' ability to reliably serve load at the lowest reasonable costs in a prudent manner. These are:

1. the Companies' position with respect to long-term generation resources and fuel supplies;
2. the Companies' agreements with respect to the mutual support that balancing areas will provide to each other;
3. the state of the capacity and demand balance in the western region (*i.e.*, wholesale power market); and
4. the Companies' activities with respect to acquiring firm supply from the market to the extent that long-term resources coupled with regional reliability agreements do not provide for sufficient reliability.

16. Q. WHICH OF THOSE FACTORS DOES YOUR TESTIMONY WITH RESPECT TO POWER PURCHASE PRUDENCE TYPICALLY ADDRESS?

A. I have testified with respect to the prudence of the Companies' power purchase activities since 2002 and in all the proceedings since the deferred energy accounting adjustment ("DEAA") process was established. Those testimonies address the Companies' activities with respect to acquiring firm supply from the market to provide the residual reliability need not met by long-term resources. The Companies have been able to serve load without resorting to load shedding and to serve that load at what has been a reasonable cost given market conditions. However, that is becoming an increasingly difficult challenge given current market conditions.

17. Q. CAN YOU DESCRIBE THE INDUSTRY STANDARD APPROACH FOR ENSURING THAT THERE WILL BE ADEQUATE CAPACITY TO RELIABLY SERVE LOAD?

A. Yes. The industry standard with respect to ensuring reliability is to look ahead the number of years it takes to develop new capacity and to take actions to ensure that sufficient capacity will be available to meet projected loads that far into the future. Currently this is done in two main ways in the United States. In areas with vertically integrated utilities with an obligation to serve, utilities are responsible for developing resource plans that look forward and for building and/or procuring long-term power purchase agreements ("PPAs") with new generation resources. The type of resource to be acquired and the method of acquisition (utility ownership or PPA) is often contentious. The level of forecasted load may also be contentious. What is not contentious is the recognition that resources must be developed on a forward-looking basis in order to reliably serve load. In areas where utilities are not fully integrated or have delegated reliability planning to independent system operators ("ISOs")/regional transmission organizations ("RTOs"), a similar process is followed at the ISO/RTO level. The ISO/RTO looks forward and determines with sufficient lead time to allow for new construction of resources what quantity of capacity is needed. In some ISOs/RTOs (*e.g.*, New England and PJM) a forward capacity auction is held in which new and existing resources bid and the ISO/RTO contracts with sufficient capacity through its FERC-approved tariff to meet reliability needs 3 to 4 years in the future. In others (*e.g.*, CAISO and NYISO), the ISO/RTO alerts utilities and regulators of impending capacity deficiencies, and there are processes to ensure that those gaps are filled by the utilities if market solutions do not come forward with sufficient lead time. This framework is essential to maintaining the resource adequacy required for reliability. Waiting past the point when new resources that are projected to be required can be developed puts reliability at risk. The framework also facilitates another key aspect of maintaining reliability which is the sharing of reserves and reliability. Unless a power system is very large and diverse, even with adequate capacity it may not be able to fully serve its own load with its own resources at all times. When each party knows that others are taking responsibility for resource adequacy, agreements to share adverse reliability outcomes are possible and the impact of these events is diminished as it is spread over multiple systems.

18. Q. DO YOU HAVE DIRECT EXPERIENCE WITH RELIABILITY AND RESOURCE PLANNING OF THIS NATURE?

A. Yes. I directed a multi-year study and working group effort on behalf of ISO-NE, NYISO, and PJM that examined the issue of forward capacity markets including a joint Northeast market. While a joint market was not developed, that effort eventually led to ISO-NE and PJM implementing individual forward capacity markets with over three years of lead time. That is, the ISO/RTO obtains commitments from capacity resources over three years before the need date. NYISO maintained a short-term capacity market, but that is backed up by NYISO's Comprehensive Reliability Planning Process and Reliability Needs Assessment which can lead to a directive from the regulator for a utility to implement a forward solution if required. In connection with work done in California, I have reviewed CAISO's local reliability needs planning process. It is also conducted several years in advance and can lead to a utility being required to develop resource solutions or to CAISO acquiring resources in advance if that is not done. Additionally, I have helped develop and implement long-term plans for many integrated utilities. There can be gaps in this process and they usually happen around regulatory transitions. For example, in 2002 Ontario had committed to close its coal plants and faced an impending reliability shortage as it had moved away from having an integrated utility with long-term reliability responsibility. I directed a project with the Ontario Ministry of Energy to put in place over 2,000 MW of capacity contracts using an RFP process from new combined cycle plants to fill that gap. Subsequently, the Province formed the Ontario Power Authority so that capacity acquisition would permanently be done several years ahead. Around the same time, Ireland faced the same situation. It had transitioned to a competitive market and forecast a shortage of capacity without any entity that was responsible for meeting the capacity need. I worked with the Irish regulator to implement an RFP for new combined cycle capacity on an emergency basis. Both Ireland and Ontario had the same problem. They had de-activated the forward-looking reliability responsibility of the incumbent utility, but had not replaced it and had to resort to non-traditional resource procurement by a government entity. The same situation applied in California in 2000 and the California Department of Water Resources had to procure the development of new capacity and had to procure emergency resources at a smaller scale in order to shorten lead times.

19. Q. CAN YOU PUT THIS IN THE NEVADA CONTEXT?

A. Nevada has an IRP process that allows sufficient lead time for new resources to be developed. Resources that will provide power for more than three years are examined in that process and can be approved with sufficient lead time for them to be developed. Developing such resources reduces or eliminates the need to acquire capacity in the market on a short lead time and short-term basis. The Companies currently maintain large open positions that must be filled on a short-term basis. When I first testified on behalf of the Companies with respect to the prudence of power purchases, the open positions were very large. That was a result of a legislated move to deregulation that was cancelled when the Western power crisis struck in 2000. Subsequent to the Western power crisis, a very large quantity of new capacity (including many large-scale combined cycle plants) was constructed on a merchant basis in Arizona and Nevada. The Company was able to acquire and construct capacity and reduce its open positions as a result of Commission approval of capacity development, capacity acquisitions, and long-term purchases through the IRP process. The large quantity of capacity that was developed resulted in a surplus regional power market that persisted for a very long time. This surplus was accompanied by multiple entities participating in power trading leading to very liquid markets. A reduced open position resulting from the acquisition of long-term power supplies combined with regional surpluses and market liquidity enabled the Companies to fill residual open positions and achieve reliability without committing to meet their reserve margin needs in advance as is typical for most utilities and to utilize relatively tight reserve margin levels. In some years, the regional excess was large enough that the Company filled the final part of its open position in very short-term markets.

But this environment has changed. Nevada ballot initiatives in 2016 and 2018, which sought to move to an open-market system and remove the Companies' responsibility for serving load, resulted in a pause in long-term resource acquisition. The market has tightened as load growth has absorbed surplus capacity and coal plants have closed. Liquidity decreased as entities have exited or reduced power trading activities and as CAISO transmission practices have led to the realization that power sourced from CAISO may not be there at the time it is needed.

20. Q. WHAT ARE THE IMPLICATIONS OF THE REGION NO LONGER HAVING SURPLUS CAPACITY, A REDUCED POPULATION OF TRADERS AND LOWER LIQUIDITY?

A. There are a variety of implications that affect the Companies. All else equal, power prices will be higher as demand is higher relative to supply. Of course, all else is never equal. In most hours power prices will reflect gas price levels and those are independent of surplus capacity. Additionally, the significant development of wind and solar resources in the region will lower prices in many hours, albeit not necessarily in hours in which the Companies need energy or capacity. The real impact is felt in hours when the region experiences extreme weather. When the region had surplus capacity, extreme weather events could push up prices, but not to the point where prices would not still be constrained by a degree of competition. Over the past several years prior to 2023, extreme weather events have pushed prices to the point where there is no effective competition to constrain prices, and entities in need of power during those events must pay whatever the market demands. This situation was not observed for any significant period of time in

2023. However, in the several years prior to 2023, extreme weather conditions resulted in extremely high day-ahead and real-time energy prices. **Exhibit Meehan-Direct-2** shows for the past ten years the average day-ahead market price at Mead for the highest week of each summer. As shown in that exhibit, the region has begun to experience extreme prices. While these are driven by weather events, they are exacerbated by a lack of surplus capacity. Given the Commission-approved adaptations to determining capacity need as described below, these increases in spot prices have limited impact as the need to purchase day ahead power on extreme weather days is less than it would have been in the past. However, there is still a major impact as the potential for these events affects the availability of forward power, the willingness of traders to offer forward power, and prices for forward power. The revealed probability of extreme spot prices drives forward prices to levels that no longer track with gas prices and limits the number of traders willing to offer forward power as selling forward power puts the seller at risk for the extreme market prices that may occur. The end result is that the Companies find it increasingly difficult to find forward blocks of power from traders to cover open positions and that such power, if available, will be at very high prices compared to the historical norm. Experience has also shown that power deliveries that are sourced from a CAISO resource and, to a lesser extent, a wheel through CAISO are at risk of curtailment in an extreme weather event. This further reduces the options available to the Companies to buy capacity on a short-term basis that is reliable.

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21. Q. HAVE THE COMPANIES TAKEN STEPS IN RESPONSE TO THE CHANGES ABOVE?

A. Yes. The Companies have increased their planning reserve requirements and have evolved their procurement to prefer non-CAISO-sourced power. The Companies have also implemented a laddering strategy that moves forward to almost two years before the summer of need, the procurement of 25% of their open position. The Companies have participated in Powerex's reverse RFP and further diversified their power sourcing. The Companies have redefined their capacity requirement to be based on the highest net hour as opposed to highest gross load hour, allowed a buffer for non-Company control area loads, and recognized that the annual peak may occur in July or August. While prudent and necessary steps, these actions will eventually face the reality that with large open positions, the evaporation of a market surplus, the reduction in liquidity that comes from a reduction in traders, and the inability to rely on CAISO-sourced power, filling the open position with short-term purchases—even with some advance purchases in line with the laddering strategy—can no longer ensure reliability. The purchases made by the Companies within the window of the laddering strategy to fill the open positions only provide reliability when the region has surplus capacity. If these surpluses do not exist, the purchases can be curtailed and while the Companies may collect liquidated damages, those will not serve load. This is a twofold problem. The first part of the problem is that non-CAISO-sourced resources will be expensive and hard to find. The second is that even if procured, these resources may not be available when most needed.

22. Q. WHAT IS REQUIRED TO ENSURE RELIABILITY IN THE CURRENT ENVIRONMENT?

A. From the perspectives of determining the capacity need and procuring short-term capacity, the Companies have done all that can be done. Procuring short-term resources further in advance of the summer than the current laddering strategy is of limited value as liquidity is limited with respect to those supplies at that time. The Companies have moved away from acquiring capacity that could be CAISO-sourced and subject to curtailment at critical times. The Companies will participate in the Western Power Pool's ("WPP") Western Resource Adequacy Program ("WRAP") that will be administered by the Southwest Power Pool ("SPP"). That will formalize reliability planning and regional support agreements and is positive. Participants in WRAP must meet minimum capacity requirements from identified and deliverable resources or face penalties. Those participants will then support each other from an operational perspective so that capacity used to meet WRAP requirements will support joint reliability and not be utilized for other purposes when needed. WRAP will require committed physically identified resources. However, WRAP only requires that resources be identified 7 months in advance. In order to be in a position to meet the WRAP requirements and to reliably serve load going forward, the Companies will have to drastically reduce their open positions by procuring more long-term capacity through the IRP process. Ideally, the open position would be fully closed three years out as is the industry standard. Failure to meet the capacity requirement will result in a financial penalty based on the full annual carrying cost of a new peaking unit. To the extent that the region develops and maintains a surplus of capacity, a small forward open position may be workable, but it presents a reliability risk and a risk of incurring significant penalties if capacity from an identified and dedicated deliverable physical resource is not available. Maintaining a large open position and filling that position with power purchased on a short-term basis that does not involve a committed and identified physical resource is inconsistent with reliably serving load in the current market environment. This practice has only worked because of regional capacity surpluses which can no longer be relied upon. Throughout the period of procuring power for 2023, the Companies have prudently adapted to challenging market conditions.

VI. FILLING THE OPEN CAPACITY POSITION

23. Q. PLEASE DESCRIBE IN ROUND FIGURES THE OPEN CAPACITY POSITION FOR THE SUMMER OF 2023.

A. As of the end of October 2021, the combined open capacity position was approximately 2,000 MW.[4] This open capacity position applies to August of 2023, and there were also smaller open capacity positions in other summer months. I reference the 2023 position as of this time as it is the first time the reported open position reflects the changes to the capacity need determination. The open capacity position will vary over time as there will be updates to the load forecast and resource capability. In this case, the open position for August 2023 was ultimately closed with roughly 2,000 MW of capacity purchases.

24. Q. PLEASE DESCRIBE HOW THE COMPANIES FILLED THE OPEN CAPACITY POSITION.

A. The Companies planned to fill the entire open position on an advance basis—that is, not to leave a portion of the open position to be filled in the month, week, or day-ahead markets as had been done prior to 2019. The Companies also planned

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[4] Monthly Energy Supply Plan Update, November 17, 2021. The open position is reported after accounting for 100 MW purchased in the October 2021 RFP.

to employ a four-season laddering strategy to fill the open capacity position over time. The Companies primarily filled the open position with purchases made through RFPs issued in the second half of 2021 (October 2021 RFP), first half of 2022 (January 2022 RFP), second half of 2022 (November 2022 RFP), and first half of 2023 (February 2023 and April 2023 RFPs). This strategy was consistent with the four-season laddering strategy that the Commission had approved and continued to approve for 2023. To cover the open positions, the Companies purchased super-peak (6x8) and on-peak (7x16) firm-priced energy products (including some with custom non-standard delivery hours to better fit the load profile and operational needs) through these RFPs. The Companies also acquired capacity by bidding in a reverse RFP issued in December 2021 by Powerex that offered non-CAISO-sourced power. In total, the Companies purchased the following through RFPs (including the December 2021 reverse RFP):

- June 2023 delivery: 150 MW of super-peak firm energy, 825 MW of on-peak firm energy, and 533 MW of custom delivery firm energy;
- July 2023 delivery: 100 MW of super-peak firm energy, 1,100 MW of on-peak firm energy, and 558 MW of custom delivery firm energy;
- August 2023 delivery: 100 MW of super-peak firm energy, 1,175 MW of on-peak firm energy, and 558 MW of custom delivery firm energy; and
- September 2023 delivery: 100 MW of super-peak firm energy, 375 MW of on-peak firm energy, and 358 MW of custom delivery firm energy.

Additionally, the Companies executed a bilaterally negotiated a 100 MW non-CAISO-sourced capacity purchase from Powerex for all summer months shortly after the November 2022 RFP and executed bilaterally negotiated 50 MW purchases for June and September in May of 2023 to fill small residual open positions for those months. This resulted in capacity positions as of the end of May

2023 that filled the Companies' open capacity positions in accordance with the approved ESPs.

25. Q. DID ANY PARTICULAR ASPECT OF HISTORICAL MARKET CONDITIONS IMPACT THE COMPANIES' PROCUREMENT TO FILL OPEN CAPACITY POSITIONS?

A. Yes. Uncertainty continued and continues to persist over the reliability of CAISO-sourced power. This concern leads to a preference for non-CAISO-sourced power. Non-CAISO-sourced power provides greater assurance that the Companies will have power available when the need is there to serve load. The Companies solicited a hierarchy of products. Product 1 was for supply that was not sourced or wheeled through CAISO. Product 2 was for supply not sourced from CAISO, but subject to a wheel through CAISO. Product 3 allowed CAISO-sourced supply. Ultimately the Companies transitioned away from purchasing CAISO-sourced supply as it was not suitable for reliability.

26. Q. WHAT FACTORS LED THE COMPANIES TO BUY SUPER-PEAK ENERGY, ON-PEAK ENERGY, AND CUSTOM-DELIVERED ENERGY TO MEET CAPACITY NEEDS?

A. The Companies analyzed their need for energy and operational issues. A mix of products was required to cover the open energy positions and meet operational concerns. Additionally, the Companies' loads were such that some of the supply change resulting from product deliveries and renewable resources starting and stopping was best shifted to hours not associated with the standard products. Most notably, the Companies solicited an hour 1-to-6 and 15-to-24 product that fit with its net load needs. The Companies procured a mix of super-peak, peak, and non-standard hour products in order to match their needs and operational requirements.

27. Q. WERE THE PURCHASES MADE THROUGH RFPS AND THE SUPPLEMENTAL BILATERAL PURCHASES MADE TO FILL THE SUMMER OPEN CAPACITY POSITION PRUDENT?

A. Yes. I examined the RFPs and RFP evaluations that were used to procure the products used to fill the open capacity position. The RFPs sought offers to sell energy and capacity to the Companies and had multiple bidders. The products solicited were determined to be consistent with open energy positions and operational concerns. These purchases were consistent with the Companies' needs from a capacity and energy perspective based on approved forecasts and resource adequacy assessment methodologies, were executed through a competitive procurement process to attract market prices, and were bought on a timeline approved by the Commission pursuant to the stipulations in the ESP proceedings. Based on discussions with Company personnel concerning the considerations associated with the 100 MW summer purchase negotiated with Powerex following the November 2022 RFP and 50 MW bilateral purchases for June and September made in May to complete the filling of the open position, I also conclude that those transactions were prudent.

28. Q. WAS IT REASONABLE FOR THE COMPANIES TO PARTICIPATE IN THE POWEREX REVERSE RFP IN DECEMBER 2021?

A. Yes. This was a conscious decision made by the Risk Committee ("RC"). Two RC meetings considered this opportunity and the Companies' bidding strategy. A special session of the RC was held for the sole purpose of approving the bidding strategy. An analysis of the market and the Companies' needs for non-CAISO-sourced capacity was presented to the RC along with an analysis of Powerex's performance during the summer of 2021. The participation opportunity was reviewed with Commission Staff. The bids placed in the reverse RFP and resulting purchases from Powerex were prudent.

VII. SPOT MARKET TRANSACTIONS TO OPTIMIZE LOADS AND RESOURCES

29. Q. PLEASE DESCRIBE HOW THE COMPANIES USE THE SPOT MARKET TO BALANCE LOADS AND RESOURCES AND MINIMIZE COSTS FOR CUSTOMERS.

A. The Companies engage in shorter-term transactions (transactions characterized by a delivery period that is less than one month) on either an hourly or day-ahead basis. These transactions are done to optimize the Companies' short-term resources to meet the Companies' load and reliability requirements. Based on my experience, this type of optimization is almost universal across utilities and represents best practices in the industry. This optimization is basically a prerequisite for running an efficient and well-functioning utility, because both the Companies' short-term resource availability—as well as their load and generation mix (which must balance)—are constantly changing. Resource availability evolves due to various factors including, but not limited to, market conditions, fuel costs, weather conditions, and the availability of Companies' generation resources. These purchases and sales are needed to integrate generation with load and with the market.

In general, the Companies' short-term transactions are executed primarily for the following three reasons:

1. Economic:
   - Transactions used to displace or "back down" the Companies' own generation resources to minimize overall costs; and

- Transactions used to sell excess power from the Companies' resources to minimize overall costs and/or balance resources with requirements.

2. Load Balancing:
   - Transactions used to meet the Companies' open position or need in either energy and/or capacity.
3. Reliability:
   - Transactions used to ensure delivery of power to the Companies' balancing area.

30. Q. DO THE COMPANIES HAVE A SET OF PROCEDURES AND GUIDELINES THAT APPLY TO THESE TYPES OF TRANSACTIONS?

A. Yes. The Companies' Power Procedures Manual governing these types of transactions is both appropriate and in line with industry practice. These procedures provide clear guidelines and controls and adequate flexibility in their interpretation and execution. For example, these procedures allow the Companies' personnel the ability to rely on their expertise to determine the precise transactions to execute when faced with short-term market movements, while ensuring that only certain types of transactions with approved creditworthy counterparties can, in fact, be executed. Therefore, this represents a reasonable, balanced, and appropriate governing set of procedures. With the institution of joint dispatch, these activities are all conducted by Nevada Power to minimize the cost of meeting the native load obligations of the Companies on a combined basis and Nevada Power goes to market on behalf of and for the benefit of the Companies.

31. Q. DO THE COMPANIES FOLLOW THESE PROCEDURES?

A. Yes. Based on on-site reviews in January 2023 and 2024 with the relevant Companies' personnel, recent discussions to confirm that practices have remained the same since that time, and a review of the appropriate Companies' documentation, I found that the Companies execute short-term transactions as set forth in these procedures.

32. Q. YOU MENTIONED EARLIER THAT THE COMPANIES PRIMARILY ENGAGE IN TWO TYPES OF SHORT-TERM TRANSACTIONS: DAY-AHEAD AND HOURLY. PLEASE DESCRIBE THE COMPANIES' DAY-AHEAD TYPE OF TRANSACTIONS.

A. Day-ahead transactions are also referred to as pre-scheduled transactions. They are done in advance of the delivery day when resources need to be scheduled for a particular delivery day. Day-ahead transactions are primarily undertaken for economic and reliability reasons. The day-ahead transaction process begins with a load forecast. During the beginning of each business day, estimates of the Company's power requirements—*i.e.*, load forecast for the current and next six days—are prepared and then updated daily for things like changes in weather. To perform this function, the Companies use load forecast software. Once this load or power requirements forecast is completed, it is used with the Companies' unit commitment and dispatch model, the short-term optimization model, to determine the day-ahead load-resources breakdown. This model determines the least cost-reliable combination of the Companies' generation units and purchases during the next day. The model incorporates things such as unit constraints—*e.g.*, minimum run requirements/ramp constraints—along with next-day natural gas prices. Additionally, with the interconnection of ON Line, the model also accounts for the potential for transmission constraints between Nevada Power and Sierra in considering joint dispatch optimization.

Once modeling is complete, the Companies have the load and resource information needed to determine the following:

1. The amount of day-ahead power that has to be purchased to meet any open positions—*i.e.*, required power purchases needed for reliability purposes.
2. The amount of MW that can be economically dispatched.
3. The cost of day-ahead Companies' owned generation used as a benchmark or price limit when determining how much Companies' generation can be displaced with market power purchases—*i.e.*, spot economy energy purchases—or can be increased to make spot market economy sales.

The Companies' personnel responsible for the preceding tasks produce reports and analyses that detail the amount of required power needed for reliability and detail a "decremental" or "avoided-cost" curve that decrements by 50 MW the cost of Companies' generation and increments generation by 50 MW to detail the incremental cost of generation that would be used if sales were made. This curve is calculated in standard units of 50 MW for on-peak and off-peak periods to provide a curve decremented (or incremented) in standard power blocks that can be easily transacted in the market. For example, this curve would state that one 50 MW block of day-ahead on-peak power costs $40/MWh, another 50 MW block costs $38/MWh, *etc*. This information is then communicated to the personnel responsible for making these transactions—*i.e.*, the day-ahead trader.

The first thing the day-ahead trader does is canvas the market to determine the market price for power. The "market" consists of, but is not limited to, counterparties that are pre-approved by the Companies (*i.e.*, meet certain creditworthy standards and have transacted with the Companies before) as well as several brokers and trading platforms such as the ICE.

The day-ahead trader is in continuous interaction with the Companies' market analytics group in order to optimize the day-ahead mix of company-owned generation and purchased power. Once all power purchases and sales are complete, the day-ahead schedule is finalized. This information is then used to update the appropriate models, position reports, and forecasts. For example, the amount of fuel that must be purchased is adjusted depending on how much generation is displaced and no longer needed. After the day-ahead fuel and power purchases/sales have been finalized and executed, the load and resource pre-scheduling personnel communicate to the generating plant personnel these results. This ensures that the generators are aware of their obligations as well as ensuring that the load and resource personnel are aware of any generator issues that could affect scheduling.

33. Q. PLEASE DESCRIBE THE COMPANIES' OTHER TYPE OF SCHEDULED SHORT-TERM TRANSACTIONS, NAMELY THE REAL-TIME/HOURLY TRANSACTIONS.

A. On the day of delivery, the real-time or hourly trader engages in various types of economic, reliability, and transmission transactions. These transactions occur on an hourly basis and are primarily driven by constantly changing real-time loads and resource conditions as compared to what was forecast in the day-ahead analysis. The trader updates the dispatch model with any information not available or known the day before both overnight as well as throughout the day. The trader also updates and runs the load forecast tool to maintain an up-to-date profile of the Companies' power requirements. The trader monitors the Companies' generation units for things like current generation availability so as to have the most complete and real-

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time information regarding all the Companies' resources and requirements. This updated information is reflected in the short-term optimization model throughout the day.

The real-time trader surveys the market and engages in similar types of transactions as the day-ahead trader and generally uses similar types of analyses. For example, the real-time trader will use the short-term optimization model results to purchase power to displace or back down the Companies' generation by making an hourly purchase in real-time or sell power if profitable. As a transaction is made, the short-term optimization model is updated to include that transaction. Again, this information flows to the appropriate personnel so that information regarding the fuel requirements can be adjusted to account for changes in generation requirements. The real-time trader also canvases the market for the most favorable price. All transactions are evaluated relative to the native load and considering prior transactions. As point-to-point transmission must be purchased for off-system sales, sales are evaluated considering transmission costs. A balanced load and resource schedule along with unit incremental and decremental costs are transmitted to the CAISO.

34. Q. HAVE YOU EXAMINED THE PRICES THE COMPANIES PAID OR RECEIVED FOR DAY-AHEAD AND REAL-TIME PURCHASES AND SALES?

A. Yes. I would like to note that there are many such transactions over the Deferral Period. I compared the prices of the Companies' day-ahead market purchases and sales to prices at the Mead trading point. All transactions are not at this point; however, this is the most proximate published price index for comparison. In **Exhibit Meehan-Direct-3**, graphs are shown for all products for which trades were

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executed in 2023. The trades are very consistent with the reported indices. The exception is that power appears to have been purchased at a price well above the published index on August 15. That only appears that way on the exhibit because there is no index published for August 15 and the chart uses an average of the two days surrounding August 15 as an index. I confirmed with the Company personnel responsible for supervising day-ahead purchases that these purchases were required to serve load and were bought at the best price available to the Companies. The unavailability of an index due to no trading activity is an example of the decreased liquidity in the market on high-priced days and the challenges that the Companies face in procuring supply during high-priced periods. With respect to hourly real-time sales there are no published indices. I did, however, compare the weighted average hourly price averaged over the hours in each day to the day ahead price for the day. **Exhibit Meehan-Direct-4** shows this comparison. As shown in that exhibit, the real-time prices reasonably track the day-ahead prices indicating that the real-time prices are aligned with the market. This exhibit is designed to identify the trending relationship between real-time and day-ahead prices. There are many reasons why average real-time prices will differ from day-ahead prices, including changes in actual conditions from expected conditions and hours with no activity; however, over time it is reasonable to expect that real-time prices should track day-ahead price levels and **Exhibit Meehan-Direct-4** shows that they do.

35. Q. DID THE COMPANIES CONTINUE REAL-TIME PURCHASE AND SALE PROCESSES THROUGH THE EIM IN 2023?

A. Yes. The Companies commenced operating in the EIM on December 1, 2015, and this has continued through 2023. Through the EIM, the Companies effectively execute short-term purchases and sales that are characterized as balancing transactions. Within the hour, the CAISO monitors load and generation over the entire EIM footprint and issues instructions to adjust generation up or down in order to balance load and generation. The Companies submit a balanced schedule to the EIM. When the Companies are instructed to increase generation relative to their schedule—if load is as forecast—they will effectively sell energy to the CAISO and receive compensation at the CAISO locational clearing price for such sales. When the Companies are instructed to decrease generation relative to their schedule—if load is as forecast—they will effectively buy energy from the CAISO and will pay the CAISO the locational clearing price for such purchases. Instructions to increase generation are issued only when the Companies' anticipated incremental costs are lower than the clearing price and instructions to decrease generation are issued only when the Companies' anticipated incremental costs are higher than the clearing price. These transactions are by definition prudent as they only occur when savings are anticipated to be realized. Prior to EIM participation, these opportunities would not arise as they were within the hour-ahead scheduling window used in the bilateral market. Additionally, if load is greater than forecasted, the Companies will be directed to increase generation if their resources are the lowest cost unutilized resources in the EIM or will buy energy in the EIM market to meet the increased load relative to the pre-hour forecast. If load is less than forecasted, the Companies will be directed to decrease generation if their resources are the highest cost utilized resources in the EIM or will sell energy in the EIM market to meet the decreased load relative to the pre-hour forecast. Prior to the EIM, all swings would have to be accommodated by the Companies' generation. By definition, purchases and sales that occur in response to load imbalances are prudent as they lower costs relative to only using internal generation.

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36. Q. DID THE COMPANIES GENERATE SHORT-TERM POWER PURCHASES AND SALES THAT APPEAR TO BE CONSISTENT WITH MARKET OPPORTUNITIES?

A. Yes. Generally, one would expect that a utility would be only occasionally exactly aligned with the market and neither buying nor selling. **Exhibit-Meehan-Direct-5** examines the Companies' monthly short-term sales and purchase activities in both real-time and day-ahead markets. This exhibit shows that the Companies are constantly transacting in significant volumes. With joint dispatch, the Companies can access a more varied market. That exhibit shows the Companies buying and selling throughout the year. This is an indication of the prudent use of market opportunities. I also note that in addition to these transactions, there are significant quantities of spot purchases and sales made through the EIM.

37. Q. DO YOU BELIEVE THESE SHORT-TERM TRANSACTIONS INCLUDING DAY-AHEAD, REAL-TIME TRANSACTIONS, AND TRANSACTIONS EFFECTED THROUGH THE EIM ARE PRUDENT?

A. Yes. It is not practical to examine each short-term transaction. However, I do not believe such an exercise is necessary, as the processes and procedures that govern these transactions are well in line with standard utility practice and are prudent. These transactions ensure that the Companies can meet their reliability requirements and keep the lights on while allowing for significant opportunities to minimize their costs on behalf of ratepayers including the sale of surplus economy energy. Based on my review of the procedures used by the Companies, a review of the circumstances applicable to critical periods in 2023, and a comparison of the prices paid or received to quoted prices, I conclude that these transactions are prudent.

VIII. CONCLUSIONS

38. Q. PLEASE SUMMARIZE YOUR CONCLUSIONS WITH RESPECT TO THE PURCHASE AND SALE TRANSACTIONS ENTERED INTO BY THE COMPANIES FOR THE DEFERRAL PERIOD.

A. My conclusions are as follows:

1. The purchases made to close the Companies' open capacity positions were prudent. The Companies assessed both capacity and energy open positions and bought to the need, implemented the purchases on a schedule consistent with the Commission-approved ESPs and evolving market and resource adequacy policy developments and primarily executed the transactions through competitive procurement processes. The decision by the RC to participate in the Powerex RFP was based on a comprehensive analysis and was prudent.
2. The spot market transactions made by the Companies to provide the power needed to reliably serve loads, to balance the Companies' loads and resources, and to minimize fuel and purchased power costs were prudent. They are reflective of industry best practices for integrated electric utilities, are made in line with reasonable and standard procedures, and compare reasonably to reported market prices.
3. The Companies' participation in the EIM resulted in intra-hour balancing purchases and sales that are prudent, as they lower costs relative to using only internal generation for balancing and are significant indications of prudent efforts to achieve the lowest possible costs for all Nevada customers.

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

A. Yes.

EXHIBIT MEEHAN-DIRECT-1

NERA
ECONOMIC CONSULTING

EUGENE T. MEEHAN
SPECIAL CONSULTANT

Mr. Meehan is a Special Consultant affiliated with NERA. He has over thirty-five years of experience consulting with electric and gas utilities and has testified as an expert witness before numerous state and federal regulatory agencies, as well as appeared in federal court and arbitration proceedings.

At NERA, Mr. Meehan's practice concentrates on serving energy industry clients, with a focus on helping clients manage the transition from regulatory to more competitive environments. He has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. In addition, he has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has experience leading NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory and business strategy, as well as development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

Education

Boston College, BA, Economics, *cum laude*
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	CONSULTANT
2015-	Special Consultant Affiliated with NERA Economic Consulting
	NERA Economic Consulting
1999-2014	Senior Vice President
1996-1999	Vice President
1973-1980	Senior Economic Analyst; Research Assistant
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President

Areas of Expertise

Restructuring/Stranded Cost Recovery

Mr. Meehan has directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulating regulatory filings to accomplish strategy. As part of these assignments, Mr. Meehan facilitated sessions with senior management to set and track filing strategy. Clients include Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing

Mr. Meehan has formulated unbundling strategies, with a specialization in generation pricing. He has advised several utilities in standard offer pricing and has testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement

Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation, with the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before FERC and state regulatory agencies on competitive power procurement. In addition, Mr. Meehan helped to design and implement the New Jersey BGS auction process.

Power Contracts

Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed and testified on the three principal types of power contracts: integrated utility to integrated utility contracts, IPP to utility contract, and integrated or wholesale utility to distribution utility contracts. He has testified in power contracts disputes on behalf of Carolina Power and Light, Duke Power Company, Southern Company, Orange and Rockland Utilities, and Tucson Electric Power. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements

In addition to his expertise on power pooling issues, Mr. Meehan has significant experience with assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets and has designed efficient specifications for retail settlement systems, including the use of load profiling, and examined the risk and cost allocation issues of alternative settlement systems.

Risk Management

Mr. Meehan has advised several large utilities on price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements, as well as provision of price managed service for various terms.

Marginal Costs

Mr. Meehan has provided comprehensive marginal cost analyses for over 25 North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning

Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes, and the prudence of particular investment decisions.

Generation Strategy

Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling

Mr. Meehan has in-depth working knowledge of the operating, accounting, and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since 1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In NEPOOL, he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to explore the impact of PJM restructuring proposals upon generating asset valuation and examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy, and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies, as well as for various utilities on the impact of pooling arrangements on strategic alternatives.

Representative Assignments

Worked with Public Service Electric & Gas Company (PSE&G) to direct a three year NERA advisory effort on restructuring. Facilitated a two-day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998, worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination, and briefing. Also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999, advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

Worked on separate assignments for a large utility in the Northeast and a large utility in the Southeast, advising on the evaluation of risk management offers from power marketers. The assignments included reviewing proposals, attending interviews with marketers and providing advice on these, and the developing analytical software to evaluate offers.

Worked with government of Ontario beginning in 2004 to help design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. Supervising NERA's portfolio-based economic evaluation on behalf of the Ontario Ministry of Energy.

Testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a soon-to-be-created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. In addition, this effort involved the review of more than 100 power contracts in the WECC.

Directed NERA's efforts, on behalf of the electricity regulator in Ireland, to design an RFP and implementation process for the purchase of 500 Mw of new generating capacity in 2003. NERA advised on the RFP, the portfolio evaluation method, and the power contract and also conducted the economic evaluation.

Reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Submitted testimony before FERC on behalf of Southern Company Service.

Worked with Baltimore Gas and Electric (BG&E) to conduct a one and one-half year consulting assignment that involved providing restructuring advice. The project began in March/April 1998 with senior management discussions and workshops on plan development and filing strategy. Advised BG&E in the development of testimony, rebuttal testimony, and public information dissemination. Worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits and in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, advised BG&E on generation valuation and unregulated generation business strategy.

Directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards, and unit contracts to determine the optimal mix of instruments to manage price risk.

Testified for XCEL Energy on the use of competitive bids for new generation needs. Examined whether XCEL was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life-of-facility contracts, in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

Advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. Defended the First Energy shopping credit proposal.

Advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. Testimony focused on retail competition in gas and electric commodity markets.

Directed NERA's effort to train selected representatives of a major European power company in American power marketing and risk management practices. The project involved numerous meetings and interviews with power marketing firms.

Led NERA's effort to advise the New England ISO on the development of an RTO filing. Examined performance-based ratemaking for transmission and market operator functions.

Examined ERCOT power market conditions during the period of time from 1997 to 1999 and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

Advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. Involved forecasting of the unbundled wholesale cost-of-service and market prices, as well as development of a regulatory strategy for gaining approval of contract restructuring and the transfer of generation from regulated to EWG states.

Performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions, and recommendations concerning credit exposure monitoring, credit evaluation processes, and credit requirements.

Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, a portion of the UK wholesale settlement system.

Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members and the evolution of full requirement power wholesale power contracts into contracts that preserve Oglethorpe's financial integrity and are suitable for a competitive environment.

Developed long run marginal and avoided costs of natural gas service, as well as avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

Review of power contracts and testimony in numerous power contract disputes

Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM and cogeneration, as well as to develop integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first of its kind in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presented strategic and financial results in order to convince senior management to initiate negotiations for the incentive plan.

Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP-based marginal capacity costs.

Provided testimony on behalf of the investor-owned electric utilities in New York State, concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool as part of various consulting assignments and in connection with the development of production simulation software.

Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

Developed and presented a two-day seminar delivered to electric industry participants in the UK (prior to privatization), outlining the structure and operation of power pools and bulk power market transactions in North America.

Benchmark analysis and FERC testimony of PGE's proposed twelve-year contract between PG&E and Electric Gen LLC (contract value in excess of $15 billion).

Responsible for NERA's overall efforts in advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions (the 2002 auction involved $3.5 billion, and the 2003 and 2004 auctions involved over $4.0 billion).

Publications, Speeches, Presentations, and Reports

Capacity Adequacy in New Zealand's Electricity Market, published in *Asian Power*, September 18, 2003

Central Resource Adequacy Markets For PJM, NY-ISO AND NE-ISO, a report written February 2004

Ex Ante or *Ex Post*? Risk, Hedging and Prudence in the Restructured Power Business, The Electricity Journal, April 2006

Distributed Resources: Incentives, a white paper prepared for Edison Electric Institute, May 2006

Restructuring Expectations and Outcomes, a presentation presented at the Saul Ewing Annual Utility Conference: The Post Rate Cap and 2007 State Regulatory Environment, Philadelphia, PA, May 21, 2007

Making a Business of Energy Efficiency: Sustainable Business Models for Utilities, prepared for Edison Electric Institute, August 2007

Perspectives on Ownership Issues for Traditional Generating & Alternative Resources: Should we allow utilities back in the market or limit ownership to merchants? A presentation presented at the Energy in the Northeast Conference sponsored by Law Seminars Intl., October 18, 2007

Restructuring at a Crossroads, presented at Empowering Consumers Through Competitive Markets: The Choice Is Yours, Sponsored by COMPETE and the Electric Power Supply Association, Washington, DC, November 5, 2007

*Competitive Electricity Markets: The Benefits for Customers and the Environmen*t, a white paper prepared for COMPETE Collation, February 2008

The Continuing Rationale for Full and Timely Recovery of Fuel Price Levels in Fuel Adjustment Clauses, The Electricity Journal, July 2008

Impact of EU Electricity Competition Directives on Nuclear Financing presented to: SMI – Financing Nuclear Power Conference, London, UK, May 20, 2009

Using History As A Guide, a presentation presented at the Electric Power Research Institute (EPRI) Conference: Electricity Pricing Structures for the 21st Century, July 14 – 15, 2011, Nashville, TN

Testimony

Forums

Arkansas Public Service Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Maine Public Utilities Commission

Minnesota Public Service Commission

New York Public Service Commission

Nuclear Regulatory Commission – Atomic Safety and Licensing Board

Oklahoma Public Service Commission

Public Service Commission of Indiana

Public Utilities Commission of Ohio

Public Utilities Commission of Nevada

Public Utilities Commission of Texas

Public Utilities Commission of New Hampshire

United States District Court

United States Senate Committee on Energy and Natural Resources

Various arbitration proceedings

Clients

American Electric Power Company

Arkansas Power & Light Company

Baltimore Gas & Electric

Carolina Power & Light Company

Central Maine Power

Consolidated Edison Company of New York, Inc.

Dayton Power and Light Company

Florida Coordinating Group

Houston Lighting & Power Company

Minnesota Power and Light Company

Nevada Power Company

Niagara Mohawk Power Corporation

Northern Indiana Public Service Company

Oglethorpe Power Corporation

Pacific Gas and Electric Company

Power Authority of the State of New York

Public Service and Electric Company

Public Service Company of Oklahoma

Sierra Pacific Power Company

Southern Company Services, Inc.

Tucson Electric Power Company

Texas-New Mexico Power Company

Illustrative List of Expert Testimony and Expert Reports

Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996.

Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998.

Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999.

Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999.

Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999.

NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.

Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999.

Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999.

Rebuttal Testimony on behalf of Niagara Mohawk, PSC Case No. 99-E-0681 Before the New York State Public Service Commission, November 10, 1999.

Arbitration deposition on behalf of Oglethorpe Power Corporation, last quarter of 1999.

Direct Testimony Before the Public Utilities Commission of Ohio on behalf of FirstEnergy Corporation, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 99-1212-EL-ETP re: Shopping Credits.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0990, February 25, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., State of Connecticut, Department of Public Utility Control, Docket No.: 00-01-11, April 28, 2000 and June 30, 2000.

Testimony on behalf of Texas-New Mexico Power Company, Fuel Reconciliation Proceeding before the Texas PUC, June 30, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the New Hampshire Public Service Commission, Docket No.: DE 00-009, June 30, 2000.

Rebuttal Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, November 22, 2000.

Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, January 19, 2001.

DETM Management, Inc. Duke Energy Services Canada Ltd., And DTMSI Management Ltd., Claimants vs. Mobil Natural Gas Inc., And Mobil Canada Products, Ltd., Respondents. American Arbitration Association Cause No. 50 T 198 00485 00, August 27, 2001.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) Docket No.: EX01050303, October 4, 2001.

Direct Testimony Before the Federal Energy Regulatory Commission on behalf of Pacific Gas and Electric Company, Docket No.: ER02-456-000, November 30, 2001.

Fourth Branch Associates/Mechanicville vs. Niagara Mohawk Power Corporation, January 2002 (Expert Report).

Arbitration Deposition on behalf of Oglethorpe Power Corporation, March 2002.

Direct Testimony and Deposition Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, July 16, 2002.

Rebuttal Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, August 13, 2002.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, in the matter of the Application of Nevada Power Company to Reduce Fuel and Purchased Power Rates, PUCN Docket No. 02-11021, November 8, 2002 and subsequent Deposition Testimony.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, Docket No. 03-1014, January 10, 2003.

Direct Testimony Before the Public Utility Commission Of Texas on behalf of Texas-New Mexico Power Company, Application Of Texas-New Mexico Power Company For Reconciliation Of Fuel Costs, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, PUCN Docket No. 02-11021, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company, Docket No. 03-1014, May 5, 2003.

Testimony Before the Public Service Commission of New York on behalf of Consolidated Edison Company of New York, Inc., Case No.: 00-E-0612, September 19, 2003.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 12, 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 12, 2004.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, May 28, 2004.

Direct Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, January 22, 2004.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, April, 2004.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 9, 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 7, 2005.

Expert Report on behalf of Oglethorpe Power Corporation, March 23, 2005.

Arbitration deposition on behalf of Oglethorpe Power Corporation, April 1, 2005.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's December 2005 Deferred Energy Case.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, January 13, 2006.

Remand Rebuttal for Public Service Company of Oklahoma before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200200038, **Confidential**, March 17, 2006

Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, April 18, 2006.

Cross-Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, May 22, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, Docket No. 06-01016, June 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386, December 22, 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 05-0315, December 29, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2007 Deferred Energy Case, January 2007.

Declaration Before the State of New York Public Service Commission, on behalf of Consolidated Edison Company of New York, Inc.'s Long Island City Electric Network, Case 06-E-0894 – Proceeding on Motion of the Commission to Investigate the Electric Power Outage and Case 06-E-1158 – In the Matter of Staff's Investigation of Consolidated Edison Company of New York, Inc.'s Performance During and Following the July and September Electric Utility Outages. July 24, 2007.

Direct Testimony Before The Public Utilities Commission of Colorado, In The Matter of the Application of Public Service Company of Colorado for Approval of its 2007 Colorado Resource Plan, April 2008.

Answer Testimony Before the Public Utilities Commission of the State of Colorado on behalf of Trans-Elect Development Company, LLC, and The Wyoming Infrastructure Authority, Docket No. 07A-447E, April 28, 2008.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Application of Sierra Pacific Power Company d/b/a/ NV Energy Seeking Acceptance of its Eight Amendment to its 2008-2007 Integrated Resource Plan, Docket No. 10-02023.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's 2008 Deferred Energy Case, February 2009.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2008 Deferred Energy Case, February 2009.

Direct Testimony Before the Public Utilities Commission of Texas, on behalf of Entergy Texas, Inc. Docket No. 33687, April 29, 2009.

Direct Testimony Before The Public Utilities Commission Of Nevada On Behalf of Nevada Power Company D/B/A Nevada Energy, 2010 – 2029 Integrated Resource Plan, June 26, 2009.

Before the Public Service Commission of New York, Case 09-E-0428 Consolidated Edison Company of New York, Inc. Rate Case, Rebuttal Testimony, September 2009.

Direct Testimony Before the Public Utilities Commission of Nevada on Behalf of Sierra Pacific Power Company's 2009 Deferred Energy Case, February 2010.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2009 Deferred Energy Case, February 2010.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2010 – 2029 Integrated Resource Plan, Docket No. 09-07003, July 2010.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Eighth Amendment to its 2008 – 2027 Integrated Resource Plan, Docket No. 10-03023, July 2010.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Application of Nevada power Company d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2010-2029, including authority to proceed with the permitting and construction of the ON Line transmission project, Docket No. 10-02009.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Petition of Nevada Power Company d/b/a NV Energy requesting a determination under NRS 704.7821 that the terms and conditions of five renewable power purchase agreements are just and reasonable and allowing limited deviation from the requirements of NAC 704.8885, Docket No. 10-03022.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company d/b/a NV Energy, 2010 Deferred Energy Case, Docket No. 10-03003, filed August 3, 2010

Rebuttal Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company d/b/a NV Energy Electric Department, 2010 Deferred Energy Case, Docket No. 10-03004, filed August 3, 2010

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 11-03003 2011 Electric Deferred Energy Proceeding, March 2011.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 11-03004 2011 Electric Deferred Energy Proceeding, March 2011.

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Rebuttal Testimony Before the Public Utilities Commission of Ohio, In Support of AEP Ohio's Modified Electric Security Plan, Case No. 10-2929, May 11, 2012.

Prefiled Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 12-03004 2012 Electric Deferred Energy Proceeding, March 2012.

Prefiled Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 12-03-003 2012 Electric Deferred Energy Proceeding, March 2012.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 13-03004 2013 Electric Deferred Energy Proceeding, March 2013.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 13-03003 2013 Electric Deferred Energy Proceeding, March 2013.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 14-02041 2014 Electric Deferred Energy Proceeding, February 2014.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 14-02040 2014 Electric Deferred Energy Proceeding, February 2014.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 15-02040 2015 Electric Deferred Energy Proceeding, February 2015.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 15-02039 2015 Electric Deferred Energy Proceeding, February 2015

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 16-03004 2016 Electric Deferred Energy Proceeding, March 2016.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 16-03003 2016 Electric Deferred Energy Proceeding, March 2016.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 17-03002 2017 Electric Deferred Energy Proceeding, March 2017.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Power Company, d/b/a NV Energy, Docket No. 17-03001 2017 Electric Deferred Energy Proceeding, March 2017.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 18-03003 2018 Electric Deferred Energy Proceeding, March 2018.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Power Company, d/b/a NV Energy, Docket No. 18-03002 2018 Electric Deferred Energy Proceeding, March 2018.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 19-03002 2019 Electric Deferred Energy Proceeding, March 2019.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 19-03001 2019 Electric Deferred Energy Proceeding, March 2019.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 20-02026 2020 Electric Deferred Energy Proceeding, February 2020.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 20-02027 2020 Electric Deferred Energy Proceeding, February 2020.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 21-03005 2020 Electric Deferred Energy Proceeding, March 2021.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 21-03006 2020 Electric Deferred Energy Proceeding, March 2021.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 22-03001 2020 Electric Deferred Energy Proceeding, March 2022.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 22-03002 2020 Electric Deferred Energy Proceeding, March 2022.

EXHIBIT MEEHAN-DIRECT-2

Highest Average Weekly Price Between June and September

Mead On-Peak Prices

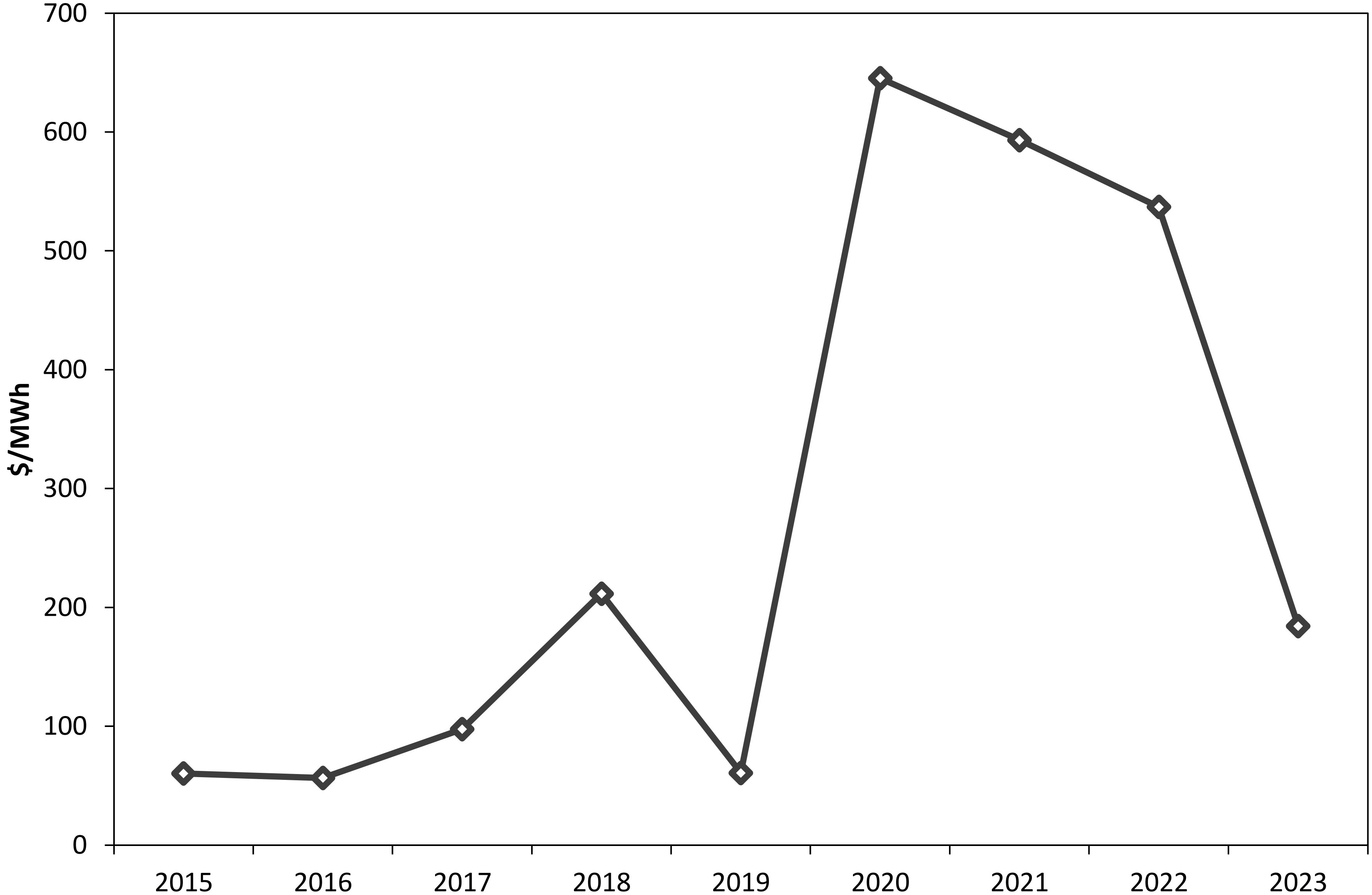
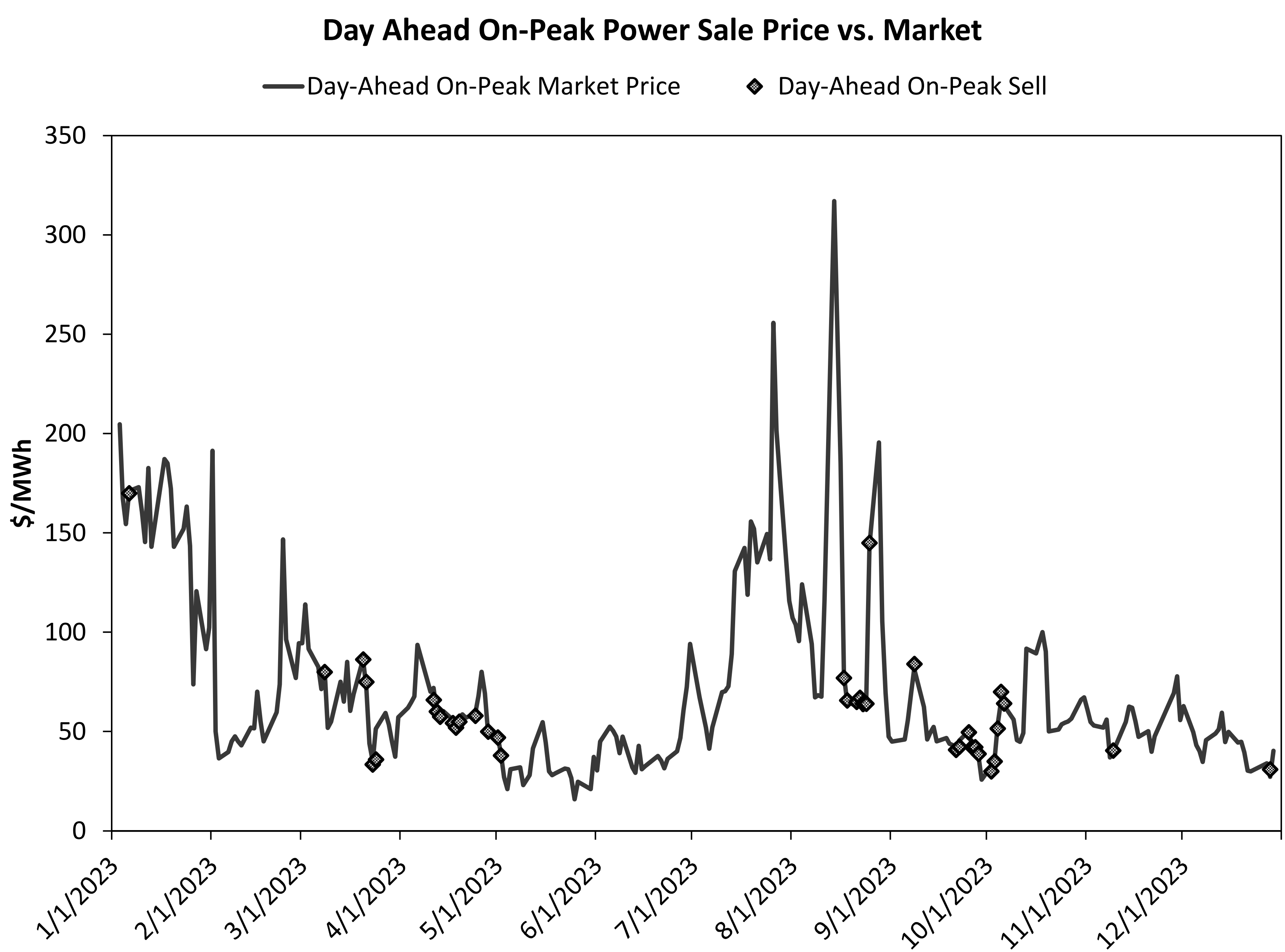


EXHIBIT MEEHAN-DIRECT-3

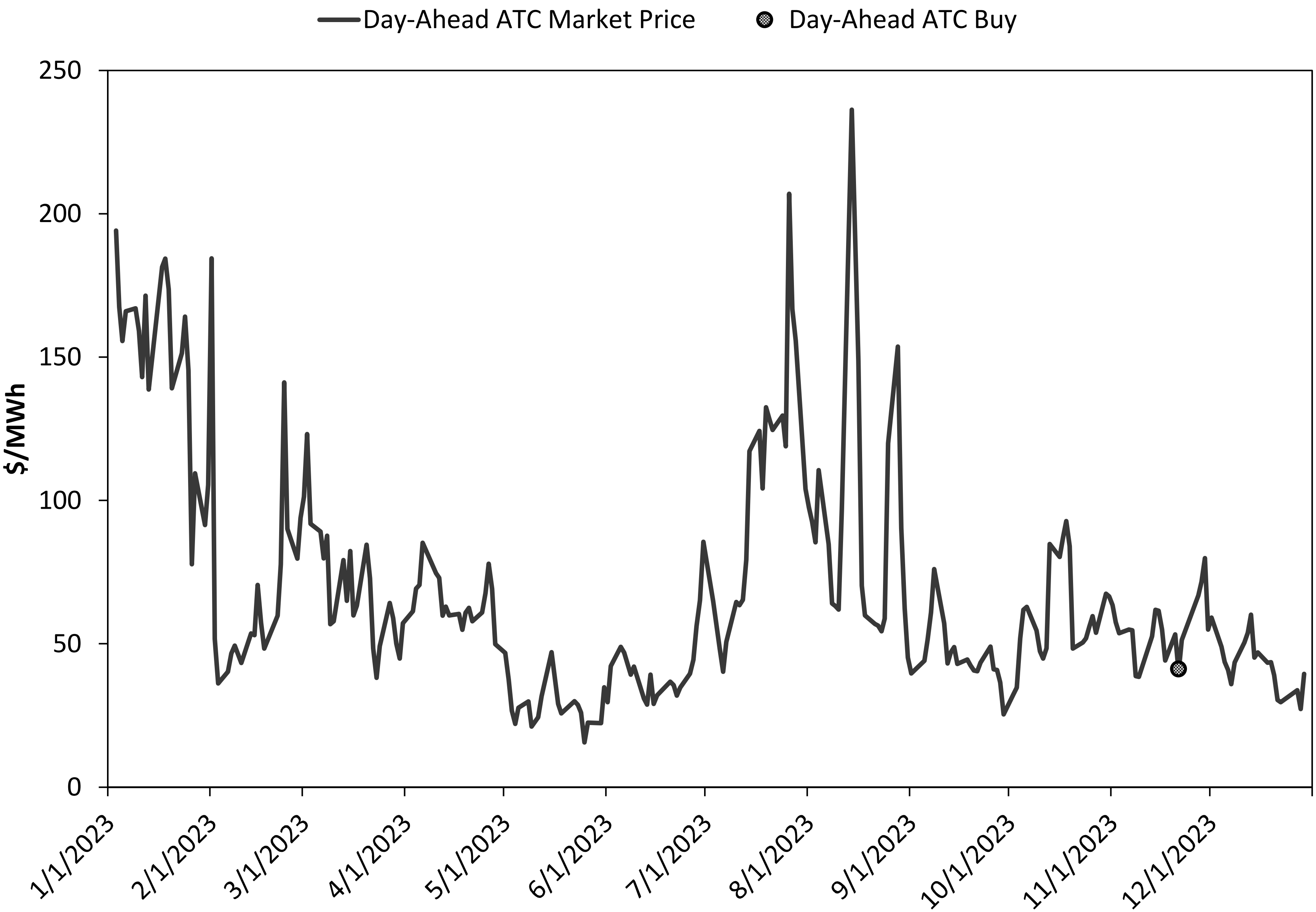
Day Ahead On-Peak Power Purchase Price vs. Market


Day Ahead On-Peak Power Sale Price vs. Market
Day-Ahead On-Peak Market Price
Day-Ahead On-Peak Sell
$/MWh
350
300
250
200
150
100
50
0
1/1/2023
2/1/2023
3/1/2023
4/1/2023
5/1/2023
6/1/2023
7/1/2023
8/1/2023
9/1/2023
10/1/2023
11/1/2023
12/1/2023

Day Ahead Off-Peak Power Purchase Price vs. Market

Day Ahead Off-Peak Power Sale Price vs. Market

Day Ahead ATC Power Purchase Price vs. Market



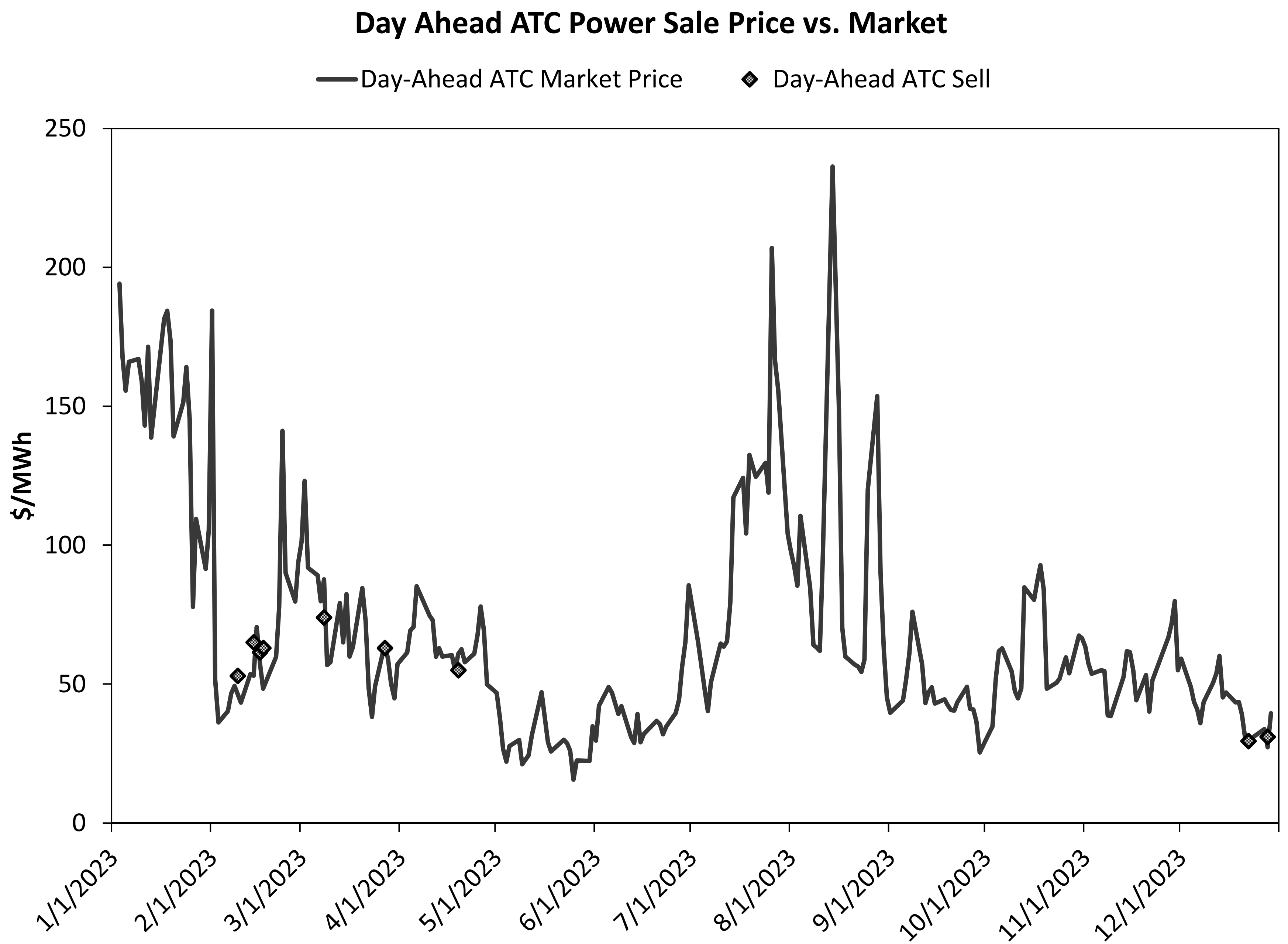

Day Ahead ATC Power Sale Price vs. Market
Day-Ahead ATC Market Price
Day-Ahead ATC Sell
$/MWh
250
200
150
100
50
0
1/1/2023
2/1/2023
3/1/2023
4/1/2023
5/1/2023
6/1/2023
7/1/2023
8/1/2023
9/1/2023
10/1/2023
11/1/2023
12/1/2023

EXHIBIT MEEHAN-DIRECT-4

Real-Time Power Purchase and Sale Prices vs. Market

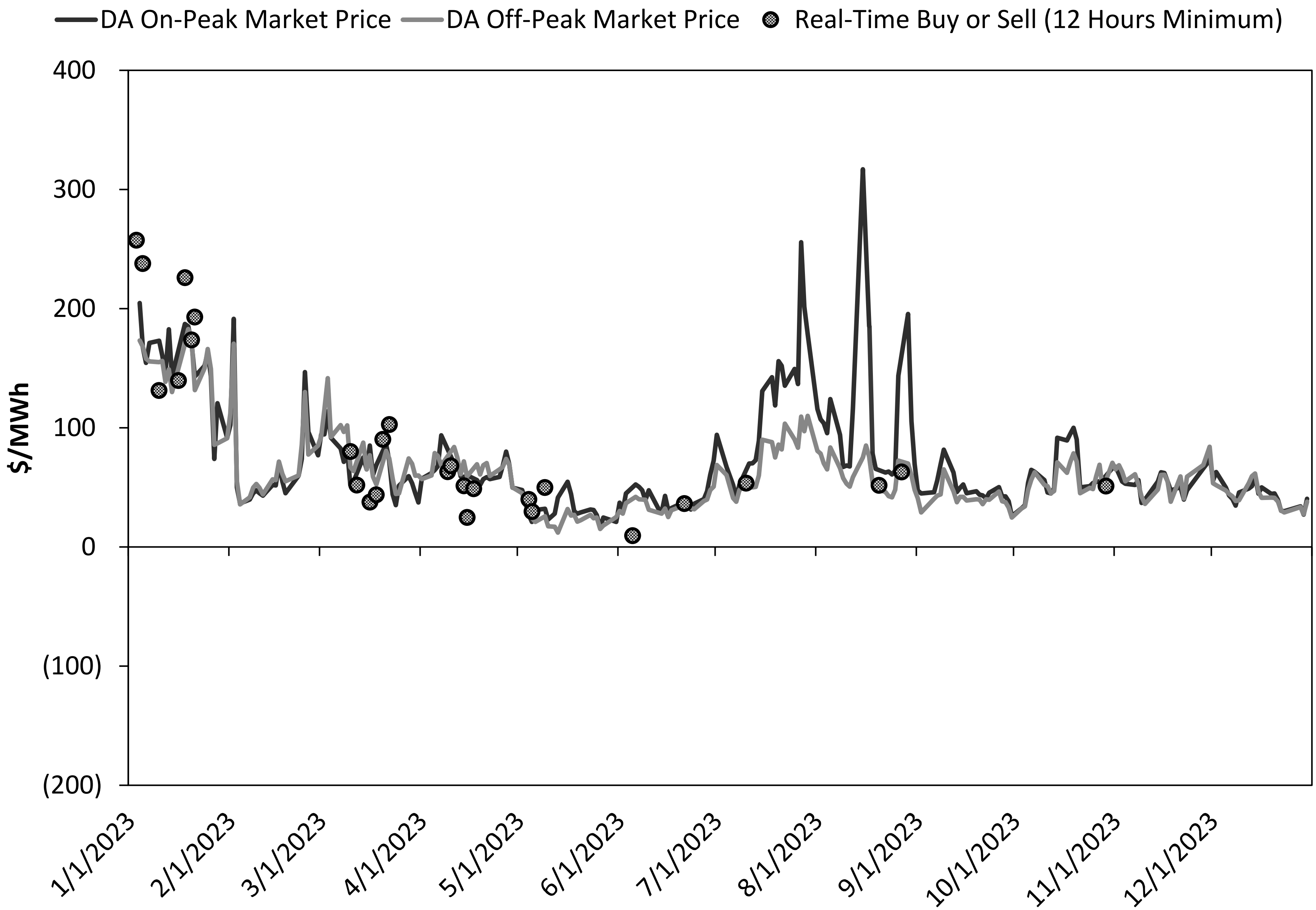
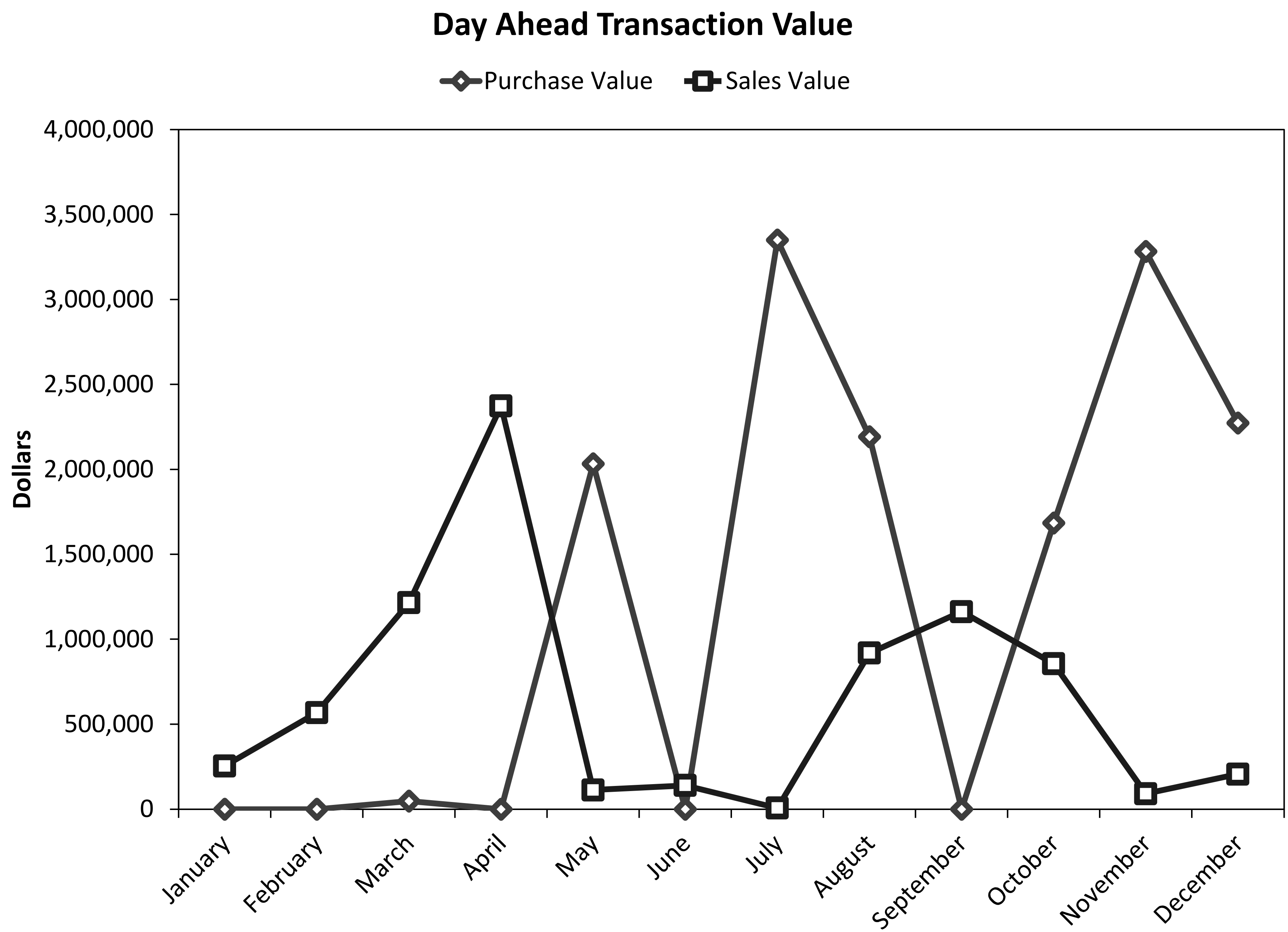
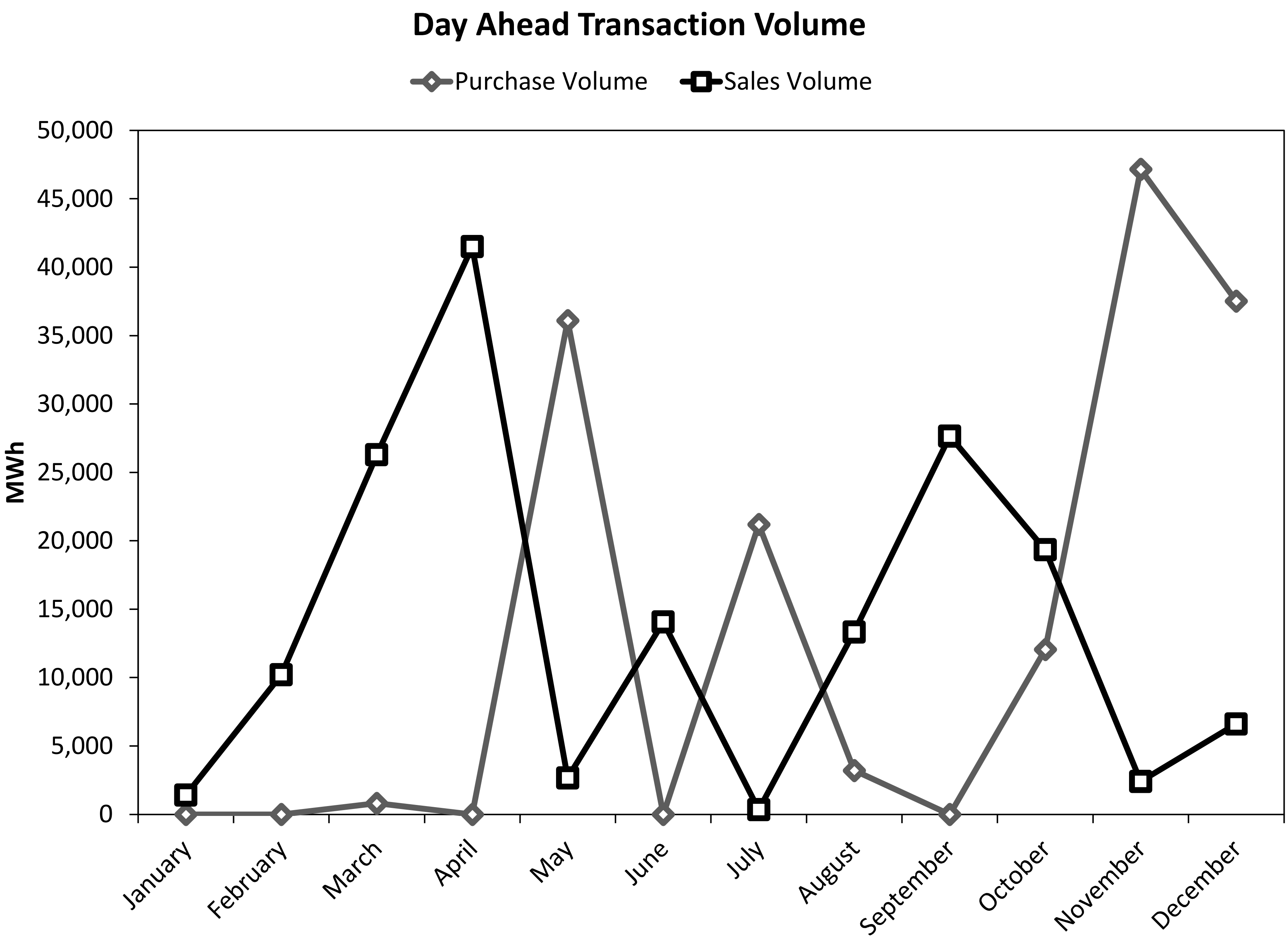
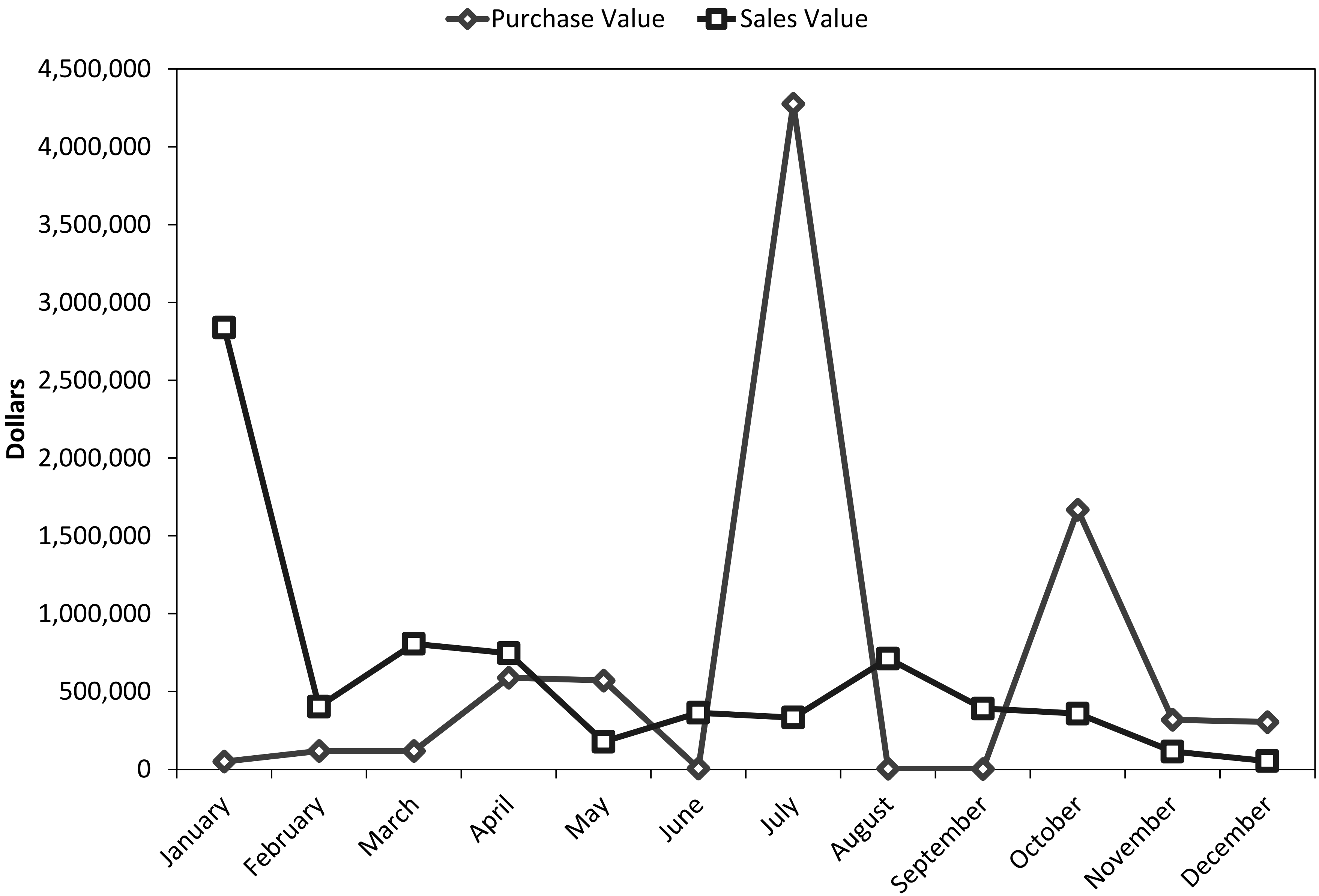


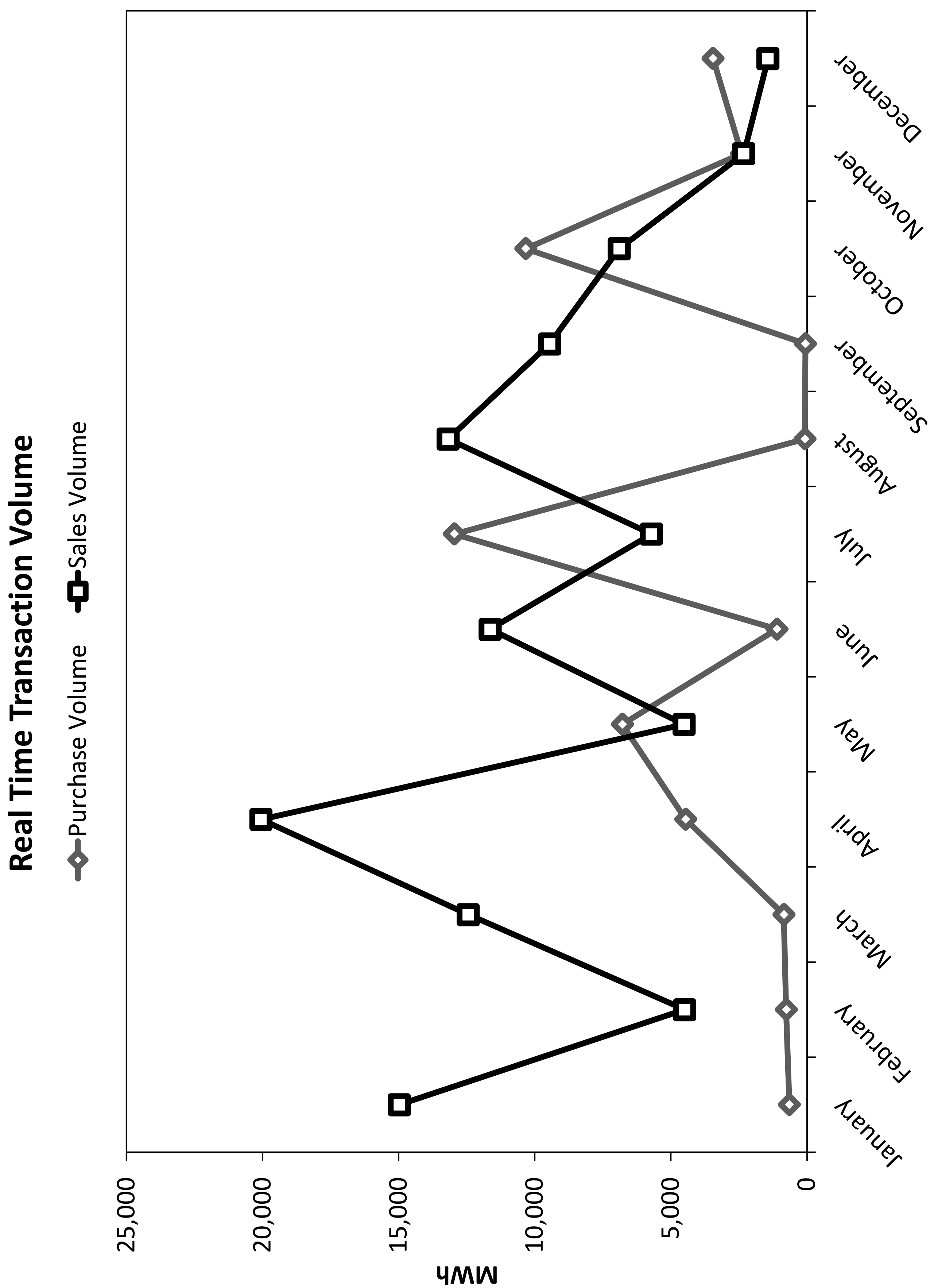
EXHIBIT MEEHAN-DIRECT-5


Day Ahead Transaction Value
Purchase Value
Sales Value
Dollars
4,000,000
3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
January
February
March
April
May
June
July
August
September
October
November
December


Day Ahead Transaction Volume
Purchase Volume
Sales Volume
MWh
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
January
February
March
April
May
June
July
August
September
October
November
December

Real Time Transaction Value




Real Time Transaction Volume
Purchase Volume
Sales Volume
MWh
25,000
20,000
15,000
10,000
5,000
0
January
February
March
April
May
June
July
August
September
October
November
December

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, EUGENE T. MEEHAN, 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 under the law of the State of Nevada that the foregoing is true and correct.

Date: March 1, 2024

Eugene Thomas Meehan

EUGENE T. MEEHAN

JENNY NAUGHTON

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Jenny Naughton

I. INTRODUCTION

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

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

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

A. I hold a Bachelor of Science degree in Finance, with an emphasis in accounting, from the University of Nevada, Reno. I joined the Companies in 2017 providing comprehensive rate analysis and support for our managed substantial energy use customers in the Major Accounts department. I later transitioned to the Regulatory Pricing and Economic Analysis department as a Pricing Specialist and assumed the role of Revenue Requirement and FERC Manager in March 2022. More details regarding my professional background and experience are set forth in **Exhibit Naughton-Direct - 1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS REVENUE REQUIREMENT AND FERC MANAGER.

A. As Revenue Requirement and FERC Manager, my responsibilities include the oversight of the preparation of the fuel and purchased power recovery rates and various deferred energy mechanisms, along with the regulatory earned rate of return and revenue requirement calculations. I also manage the completion of various Public Utilities Commission of Nevada ("Commission") and Federal Energy Regulatory Commission ("FERC") reporting requirements.

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

A. Yes. I have previously testified before the Commission in several dockets which are listed in **Exhibit Naughton-Direct–1**. Most recently I filed testimony in Sierra's latest general rate case proceeding, Docket No. 24-02026.

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

A. The purpose of my testimony is as follows: First, I sponsor the calculation of the earned rate of return and explain why the Company is not requesting an Energy Efficiency Implementation Rate ("EEIR") adjustment rate. Second, I discuss and sponsor the calculation of the backward-looking Amortization Energy Efficiency Program Rates ("EEPR") and EEIR energy efficiency rates. Next, I discuss the Company's application in May 2023, Docket No. 23-05029, to adjust the Deferred Energy Accounting Adjustment ("DEAA") in excess of the maximum allowable adjustment under NRS 704.110(10) to provide a discounted rate effected July 1, 2023 and the impacts of this deviation Finally, I discuss the annual filing for earnings sharing using the same mechanism, with a proposed adjustment, as stipulated in Sierra's 2019 General Rate Case ("GRC"), Docket No. 19-06002.[1]

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

A. Yes. I am sponsoring the following Exhibits and Appendices:

- **Exhibit Naughton-Direct-1** Statement of Qualifications;
- **Exhibit Naughton-Direct-2** Earning Sharing Methodology;
- **Exhibit Naughton-Direct-3** Proposed Earning Sharing Methodology Update;
- **Exhibit F** Earned Rate of Return;
- **Exhibit K** Calculation of the per-kilowatt hour ("kWh") rate used to clear the deferred EEIR and EEPR balances;
- **Exhibit K-1** Summary of the Energy Efficiency and Conservation ("EE&C") program cost information jointly supported with Ali Sheikh that is an input to the per-kWh calculation in Exhibit K;
- **Exhibit K-2** The accrued energy efficiency implementation revenue by month for the Deferral Period;
- **Exhibit M** Earning Sharing Calculation;
- **Appendix 4** Earned Rate of Return Work Papers; and
- **Appendix 7** Earning Sharing Calculation Work Papers.

[1] See Final Order, ⁋ 2, PUCN Docket 19-06002, issued December 23, 2019.

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

II. EARNED RATE OF RETURN

7. Q. PLEASE DESCRIBE EXHIBIT F.

A. Exhibit F is a two-page document that provides the calculation of the Company's jurisdictional earned rate of return for its electric department, as of December 31, 2023, utilizing ending and average rate base.

Page one contains the earned rate of return for the Nevada jurisdiction for each quarter from January 1, 2023, to December 31, 2023 (the "Deferral Period"), reflecting ending rate base in compliance with NRS § 704.187(2) and Nevada Administrative Code ("NAC") § 704.150(3) for Deferred Energy Accounting. The Company's earned rate of return at the end of the deferral period was 5.71 percent, which is below the authorized rate of return of 6.75 percent without incentives, and 6.85 percent with incentives, used to set the rates that were effective during the Deferral Period.

Page two contains the earned rate of return for each month of the Deferral Period, reflecting average rate base, in compliance with NAC § 704.9523(3)(c). The Company uses actual sales to calculate the earned rate of return as shown in Exhibit F. This information is also used to determine whether to clear the EEIR balances.

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

8. Q. NAC § 704.150(3) ADDRESSES CARRYING CHARGES. PLEASE PROVIDE A BRIEF DESCRIPTION OF HOW THE COMPANY APPLIED THIS REGULATION AND INDICATE WHETHER THE COMPANY COMPLIED WITH THIS REGULATION DURING THE DEFERRAL PERIOD.

A. As specified in NAC § 704.150(3), if the Company's quarterly earned rate of return exceeds the rate of return (with or without incentives) last authorized by the Commission and the average monthly deferred energy balance is a debit, an adjustment amount will be calculated equal to the amount which exceeds the utility's last authorized rate of return. The Company calculated its earned rate of return quarterly for the purpose of calculating carrying charges on the Deferred Energy balance. The average balances were debits every month, but the Company did not over-earn and thus no adjustments were made to reduce the balance applicable to carry charges for this reason.

9. Q. HAS THE COMMISSION ADOPTED A SIMILAR REGULATION ADDRESSING CARRYING CHARGES FOR THE ENERGY EFFICIENCY PROGRAM OR IMPLEMENTATION RATE BALANCING ACCOUNTS?

A. Yes. NAC § 704.9523(7)(b) states:

> The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the unamortized balance in the subaccounts of FERC Account No. 182.3. If, in any month, the balance in a subaccount of FERC Account No. 182.3 is a debit, an adjustment amount must be calculated in an amount equal to the amount which exceeds the electric utility's last authorized rate of return that was used to set rates for the electric utility or any remainder after the rate of return has been applied to the carrying charge calculation for deferred energy pursuant to NAC 704.150.

10. Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE EEIR BALANCES PURSUANT TO NAC § 704.9523(7)(b)?

A. No. The total of the EEIR balances was a credit; and therefore, no adjustment was required pursuant to the regulation.

11. Q. THE COMPANY HAS REQUESTED AN EEIR AMORTIZATION BUT NOT AN EEIR ADJUSTMENT RATE. PLEASE EXPLAIN.

A. NAC § 704.9523(4) requires lost revenue, or EEIR adjustment collections to be refunded if the utility's earned rate of return exceeds the rate of return used to establish rates as of the end of the test year. Since Sierra's earned rate of return at December 31, 2023, calculated on an average rate base is below the authorized rate of return from Docket No. 22-06014, the lost revenue collected in 2023 is not required to be refunded to customers.

III. ENERGY EFFICIENCY AMORTIZATION RATES

12. Q. WHAT ARE THE PROPOSED ENERGY EFFICIENCY PROGRAM ("EEP") AND ENERGY EFFICIENCY IMPLEMENTATION ("EEI") AMORTIZATION RATES?

A. The proposed EEP and EEI amortization rates are found in Exhibit K on lines 16 and 32, respectively. The proposed EEP amortization rate is a credit of $0.00017 per kWh and the proposed EEI amortization rate is $0.00000 per kWh. The impact of these rate changes are shown in Exhibit G, supported by Brian Ahlstedt.

13. Q. PLEASE DESCRIBE EXHIBITS K, K-1, AND K-2.

A. Exhibit K is a summary of the calculation of amortization rates to clear balances for Sierra's EEP and EEI accounts, per kWh, as requested in this proceeding. Consistent with the regulations adopted by the Commission in Docket No. 09-07016, Sierra has calculated separate amortization rates for EEP and EEI by dividing costs by deferral period kWh sales. The proposed EEPR and EEIR amortization rates are found in Exhibit K on lines 16 and 32, respectively.

Exhibit K-1 provides a synopsis of monthly activity in the EEP account for the Deferral Period. The exhibit also illustrates the calculation of carrying charges. Mr. Sheikh supports the 2023 EE&C program costs in this proceeding.

Exhibit K-2 provides a summation of monthly activity in the EEI account for the Deferral Period. The exhibit also illustrates the calculation of carrying charges.

14. Q. HAS THE COMPANY REFLECTED ADJUSTMENTS TO EXHIBIT K AND EXHIBIT K-2 IN COMPLIANCE WITH NAC § 704.9523 SECTIONS 4(A) AND (B)?

A. No. Because Sierra's Earned ROR on December 31, 2023, calculated on an average rate base, is below the authorized ROR in Docket No. 22-06014, an adjustment related to NAC § 704.9523(4)(a) and (b) to reclassify the 2023 EEI base revenue to a regulatory liability is not required.

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15. Q. PLEASE DESCRIBE THE COSTS REMAINING IN THE CURRENT PERIOD 14, EEI ACCOUNT 182-365.

A. The remaining costs in the Period 14 EEI Account 182 regulatory asset include the reclassification of the balance in EEI Period 12, the reclassification of the balance in EEIR Adjustment Period 12, and all associated carry charges.

IV. APPLICATION FOR DEVIATION

16. Q. PLEASE EXPLAIN THE COMPANY'S APPLICATION FOR DEVIATION IN DOCKET NO. 23-05029.

A. As discussed in the prepared Direct testimony of Company witness Ryan Atkins, there was a significant western pricing event due to various factors, that affected natural gas prices from December 2022 through January 2023. After an already volatile period where natural gas prices had continuously increased over the prior 12 to 18 months, this event drove natural gas prices even higher, significantly increasing the cost to the Company to continue to reliably serve its customers. For comparison purposes, Sierra's electric Base Tariff Energy Rate ("BTER") that went into effect on July 1, 2021, was $0.03698/kilowatt-hour ("kWh"). The calculated BTER that was going into effect on July 1, 2023, the first period where the full elevated costs from the western pricing event would have been included, increased to $0.07456/kWh, a 102 percent increase within 24 months. In relation, Sierra's electric deferred energy balance had been consistently growing, due to the volatility of natural gas prices, ultimately peaking in December 2022 at $224.0 million, which had increased by $20.6 million in that month alone. Based on that balance, Sierra's electric DEAA would have increased from $0.00431/kwh in July 2021 to a calculated rate of $0.01779/kWh in July of 2023. Together, the combined energy component of the customers' bills would have totaled $0.09235/kWh, as demonstrated below in **Table Naughton-Direct-**1, the highest rate since at least 2010, and certainly since the quarterly rate adjustment process went into place in 2011.

Table Naughton-Direct-1

Rate Effective Date	BTER	DEAA (Without Deviation)	Total	Rate in effect based on balance as of	Deferred Energy Balance DEAA was Based on (thousands)
7/1/2021	$0.03698	$0.00431	$0.04129	3/31/2021	$ 34,304
10/1/2021	$0.04117	$0.00681	$0.04798	6/30/2021	$ 57,155
1/1/2022	$0.04527	$0.00931	$0.05458	9/30/2021	$ 93,528
4/1/2022	$0.04801	$0.01029	$0.05830	12/31/2021	$ 85,613
7/1/2022	$0.04841	$0.00779	$0.05620	3/31/2022	$ 61,053
10/1/2022	$0.05429	$0.01029	$0.06458	6/30/2022	$ 91,491
1/1/2023	$0.06704	$0.01279	$0.07983	9/30/2022	$ 205,306
4/1/2023	$0.07341	$0.01529	$0.08870	12/31/2022	$ 223,996
7/1/2023	$0.07456	$0.01779	$0.09235	3/31/2023	$ 159,002

Recognizing how high rates had risen, and in response to feedback received from customers, the Company proactively took steps to provide rate relief to its customers by filing the deviation during the summer months when energy bills are often higher.[2] In its application, the Company requested to adjust the quarterly DEAA that went into effect on July 1, 2023, to $0.00000/kWh, an adjustment more than the maximum allowed by statute during a quarterly adjustment, resulting in a combined BTER and DEAA of $0.07456/kWh. Additionally, this request resulted in a 16 percent overall decrease from the previous quarter, avoiding yet another rate increase.

[2] See Direct Testimony of Mike Behrens, Docket No. 23-05029.

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17. Q. DID THE COMPANY PERFORM ANALYSIS TO DETERMINE THE FINANCIAL IMPACTS THE DEVIATION WOULD HAVE AND SPECIFICALLY ON THE DEFERRED ENERGY BALANCE?

A. Yes. As was explained in the Application in Docket No. 23-05029, the Company assessed the impact from various perspectives. Of greatest concern were the Company's cash flow, credit metrics, and the seemingly inevitable delay in recovering the full deferred energy balance with the change to the rate. The Company performed analysis and determined that it could effectively manage its cash flow and credit metrics in order to deliver this savings to its customers. Moreover, the Company was confident that the elevated BTER was sufficient to recover the deferred energy balance as natural gas prices had consistently been decreasing since the earlier part of the year.

Analysis was performed based off projections that contained actuals through March 2023. Without any deviation, the deferred energy balance was projected to reach $0 in November 2023. The projection scenario that incorporated only the July 1 deviation extended that to April 2024, at that time. The Company recognized that this would result in increased carry charges, but ultimately determined that the long-term rate relief benefits would outweigh the slight impact of the increased carry. Additionally, the Company stipulated to forego $3 million of carry charges, to be discussed in further detail below, to mitigate this concern. Most notably, the most recent projections that the Company performed based on January 2024 actuals are showing that the electric deferred balance will be fully recovered within the first quarter of 2024, and rates are expected to continue to decrease, reaching 2022 levels, through at least the middle of 2025.

18. Q. PLEASE DISCUSS THE CONDITION OF THE STIPULATION TO FOREGO $3 MILLION IN CARRY CHARGES.

A. As previously mentioned, the Company understood the concerns about the impact the delayed recovery of the deferred balance would have on the carry charges that the Company is typically allowed to earn, pursuant to NAC § 704.150. As part of the Stipulation entered into with the Regulatory Operations Staff ("Staff") and the Office of the Attorney General, Bureau of Consumer Protection ("BCP"), the Company agreed to forego $3 million of carry charges it would normally have received as a result of the deviation, representing a portion of the carry charge attributed to the incremental difference in the deferred energy regulatory asset balance for the years 2023 and 2024 .[3] The $3 million was allocated proportionally across Sierra Gas, Sierra Electric, Nevada Power residential and Nevada Power non-residential as of June 30, 2023 (as shown below in **Table Naughton-Direct-2**), and then was amortized over the time period the Company expected the respective balances to reach zero.

Table Naughton-Direct-2

Company	DEAA Balance @ 06/30/2023	% of Total	Disallowance
SPPC gas	$ 56,223,585	6.15%	$ 184,427
SPPC electric	83,000,365	9.08%	272,261
NPC Residential	373,958,986	40.89%	1,226,674
NPC Non-Residential	401,385,011	43.89%	1,316,638
Total	$ 914,567,947	100.00%	$ 3,000,000

[3] Stipulation dated June 15, 2023, at ⁋ 1, Additional Provisions, Docket Nos. 23-05028, 23-05029, and 23-05030.

V. EARNING SHARING

19. Q. PLEASE DESCRIBE EXHIBIT M.

A. Exhibit M is a two-page document that provides the calculation of the Company's regulatory return on equity and subsequent earning sharing calculation based on a five-quarter average as of December 31, 2023.

20. Q. PLEASE SUMMARIZE YOUR TESTIMONY WITH REGARDS TO EARNING SHARING.

A. As directed in the order in Docket No. 17-06003,[4] the Company worked informally with the Regulatory Operations Staff ("Staff") and the Bureau of Consumer Protection ("BCP") to develop a consensus on the details of the regulatory return calculation that would form the basis of the earnings sharing calculation. The regulatory return on equity and earnings sharing calculations that were filed and approved by the Commission in Nevada Power's 2019 DEAA, Docket No. 19-03001, represent the results of those discussions. As noted above, a similar methodology was applied to calculate the Sierra earning sharing in accordance with the stipulation in Docket No. 19-06002. This approved methodology, as described in **Exhibit Naughton-Direct-2**, was applied to this 2023 earning sharing filing, with one adjustment as described later and presented in **Exhibit Naughton-Direct-3**. Additionally, the Companies completed an effort begun in 2023 to redevelop the model that performs the calculation, improving the accuracy and efficiency of the model, while ensuring the intention of the approved methodology was maintained.

[4] See Final Order, ¶ 475, PUCN Docket No. 17-06003, issued December 29, 2017.

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21. Q. HOW ARE "SHARED EARNINGS" DETERMINED?

A. Shared earnings are determined by comparing the adjusted operating income to an imputed allowed operating income based on a 9.8 percent allowed return on equity,[5] or 30 basis points above the authorized return on equity of 9.5 percent.[6] The difference is then multiplied by 50 percent to arrive at preliminary earnings sharing amount, before being grossed-up for taxes to determine the amount to be recorded within the regulatory liability.

22. Q. WHAT ADJUSTMENT TO THE METHODOLOGY IS THE COMPANY PROPOSING AND HAS THE COMPANY UTILIZED THIS APPROACH FOR THE CURRENT FILING?

A. The adjustment the Company is proposing is related to the treatment of Investment Tax Credits ("ITCs"). In the original approved methodology, ITCs were included as Rate Base Item 10c and Income Statement Item 26e and assigned the _8 allocator, which applied an allocation that aligned with Net Electric Plant in Service. During development of the new model, discussed in more detail next, the inclusion of the ITCs was reviewed, and ultimately determined that this inclusion poses a potential Internal Revenue Service ("IRS") normalization violation for the items that were historically recorded. Accordingly, the Company proposes excluding the ITCs that had been historically included to avoid violating said normalization rules. This methodology was utilized in Exhibit M and does slightly decrease the imputed return on common.

[5] See Final Order, ⁋ 932, PUCN Docket 22-06014 (iss. Dec. 22, 2022).

[6] See Final Order, ⁋ 71, PUCN Docket 22-06014 (iss. Dec. 22, 2022). The 30 basis point band was an expansion of the previous 20 point band stipulated to in Docket 19-06002, to align with Nevada Power.

An exception does exist with regard to the normalization rules that pertains to battery energy storage systems ("BESS"). BESS are eligible for exemption, and thus in the event the Company places any into plant in service, the applicable ITC would be included as a rate base reduction.

23. Q. HAVE THERE BEEN PREVIOUS CHANGES TO THE METHODOLOGY SINCE IT WAS APPROVED IN DOCKET NO. 19-03001?

A. Yes. In Nevada Power's 2020 DEAA filing, the Company addressed the need to develop the current year earnings sharing accrual by adding back the current year earnings sharing accrual to properly calculate the regulatory return on equity.[7]

24. Q. PLEASE DISCUSS THE NEW MODEL IMPLEMENTED IN 2023 AND THE BENEFITS GARNERED FROM IT.

A. In an ongoing goal of enhancing accuracy, efficiency, and error mitigation in reporting, the Companies prioritized the implementation of a redeveloped Earning Sharing model in 2023. The prior model that was built and operated within Excel faced limitations of complex formulas that were difficult to follow, excluded data during the creation rather than recategorizing items as non-rate base, and included many tabs of data that made the calculation more difficult to review. Recognizing the need for a more comprehensive approach, the Companies redeveloped the model within Workiva's WDesk cloud-based application, which initiates its calculations from the general ledger data as a starting point, thereby ensuring a complete holistic inclusion of financial data. By leveraging existing financial reporting data, this shift allows for inputs and adjustments to be more transparent reducing the potential for errors. Moreover, the updated model utilizes enhanced

[7] *See* Docket No. 20-02026, Direct Testimony of Blake Groen Q&A10, page 4. It is important to note that Nevada Power's 2020 DEAA was resolved by stipulation and approved by the Commission.

built-in check figures and error checks, creating a more robust and reliable framework for financial calculations. No loss of functionality has occurred, and a fully executable working file is still produced and will be provided with the filing. The updated model did not change the underlying calculation, just the model used to calculate the earnings sharing.

25. Q. HOW IS THE IMPUTED ALLOWED OPERATING INCOME DETERMINED?

A. The imputed allowed operating income is based on the Company's weighted average cost of capital (also referred to as the 'rate of return') multiplied by the adjusted rate base. The Company's weighted average cost of capital uses a 9.8 percent cost of equity and five-quarter averages for the cost of debt components. This calculation remains the same within the new model.

26. Q. ARE THERE ANY ADJUSTMENTS MADE?

A. For purposes of calculating earnings sharing, the following adjustments are excluded in the regulatory return on equity calculation:

- Accruals for earnings sharing;
- Long-term incentive plan accruals;
- Natural Disaster Protection Plan ("NDPP") related plant items[8]; and
- Expanded Solar Access Program ("ESAP") related plant items[9].

[8] Recovered through separate rate mechanism
[9] Recovered through separate rate mechanism

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27. Q. HOW ARE THE BALANCING ACCOUNTS AND THE REVENUE RELATED TO THE COMPANIES' VARIOUS PUBLIC POLICY PROGRAMS ACCOUNTED FOR WITHIN THE MODEL?

A. The balancing accounts that exist for the Companies to track the accounting of the various public policy programs are considered "Non Rate-Base". Within the model, since the basis is the general ledger, the balances are included for transparency, however they have no impact on the earning sharing calculation due to their categorization as Non Rate-Base.

With regard to the revenue, it is recorded to a revenue account, but the alternate side of the accounting entry is an amortization or expense that reduces the balancing account. Together, the revenue and expense offset each other to zero and thus have no impact on operating income.

28. Q. WHAT APPROACH WAS TAKEN TO ADJUST THE CALCULATION FOR THE FACT SIERRA HAS A GAS DEPARTMENT?

A. The gas department's revenue and operating and maintenance accounts are in unique FERC accounts and easily segregated. FERC accounts 901 through 935 are generic to both utilities. Sierra's accounting system allows for the query of product type 700 to identify and subsequently remove gas department costs from these accounts. The remaining operating, maintenance, administrative and general electric division costs are then allocated between the state and federal jurisdictions in a similar fashion performed for Nevada Power's earning sharing calculation.

The cost of capital uses the total Sierra capital structure and total debt costs. Regulatory assets and liabilities are identified on an individual basis between electric and gas.

29. Q. WHAT IS THE REGULATORY RETURN ON EQUITY AND THE AMOUNT OF EARNINGS SUBJECT TO SHARING FOR THE PERIOD ENDED DECEMBER 31, 2023?

A. The return on equity and basis for earning sharing for 2023 is 5.94 percent, which is below the threshold of 9.8 percent. As such, there is no amount of earnings subject to the earnings sharing mechanism.

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

A. Yes.

EXHIBIT NAUGHTON-DIRECT-1

STATEMENT OF QUALIFICATIONS

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

Ms. Naughton has been an employee of NV Energy since 2017, where she has spent time in the Major Accounts and Regulatory Pricing & Economic Analysis departments, but transitioned to the role of Revenue Requirement & FERC Manager within the Revenue Requirement & Regulatory Accounting group in March 2022. Her current responsibilities are focused upon monthly, quarterly, and annual fuel and purchased power and deferred energy recovery mechanisms and their corresponding rate development and required filings, along with the preparation of regulatory earned rate of return and revenue requirement calculations. She also oversees the preparation of various regulatory filings with both the Public Utilities Commission of Nevada ("PUCN") and the Federal Energy Regulatory Commission ("FERC").

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

Professional Experience

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

- Manage the preparation of fuel and purchased power recovery and various deferred energy mechanisms and their required filings
- Oversee the preparation of regulatory earned rate of return and revenue requirement calculations in compliance with regulations and Commission directives for state and FERC jurisdictional filings
- Responsible for the completion of various state and FERC reporting requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Prior Testimony Before the Public Utilities Commission of Nevada

22-06014 22-09002 23-003005 23-03006 23-03007 23-06007 23-09003

Education

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

EXHIBIT NAUGHTON-DIRECT-2

NEVADA POWER COMPANY
EARNINGS SHARING CALCULATION METHODOLOGY

NEVADA POWER COMPANY
d/b/a NV ENERGY
EARNINGS SHARING CALCULATION METHODOLOGY

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Nevada Power Company

Regulatory Return on Equity Calculation

Proposal

An objective of this proposal is to keep the regulatory return on equity calculation auditable and consistent with Nevada Power Company's ("Nevada Power") FERC Form 1 and Form 3Q filings. Similarly, this proposal avoids the need for the voluminous detail required for a traditional rate filing, while arriving at a calculation that is reasonable and acceptable to all parties.

The proposed calculation yields an "imputed" return. As discussed in more detail below, the Nevada Power's electric retail jurisdictional operating income (before any provision for revenue sharing for Nevada Power under the provisions of Docket No. 17-06003) is divided by the Nevada Power's electric retail jurisdiction rate base (i.e., the 5-point average of each of the last five quarter ending balances) to arrive at an actual overall rate of return on rate base. The weighted average embedded cost of capital for preferred and long-term debt are subtracted from this rate of return, with the difference divided by the Nevada Power's common equity percentage. The weighted average embedded cost of capital is based on 5-point quarterly balances. An example calculation is presented in Attachment 3. Nevada Power will submit this calculation by March 1st following the calendar or fiscal year-end. From a procedural perspective, the filing could be set as stand-alone, or potentially submitted with the annual deferred energy accounting adjustment filing.

Generally speaking, Nevada Power will provide two different electric services from the same set of assets (i.e., retail and wholesale services). Nevada Power will sell energy directly to end users, and the Nevada Retail Jurisdiction reflects the return on investment from the sale of electricity to end users located in Nevada. Nevada Power will also provide wholesale electric services; specifically, the Company sells energy to other companies that resell the energy to end users and the Company provides transmission service to customers who transport energy across the Nevada Utilities transmission system. The FERC Jurisdiction return reflects the return on investment from the sale of wholesale services. Because Nevada Power provides retail and wholesale service from a common set of assets, investment and operation and maintenance expense must be allocated between the Nevada Retail and FERC Jurisdictions.

The Company's earnings sharing mechanism methodology is the outcome of discussions between the Company, PUCN Staff and BCP. Any modifications to the return or earnings sharing calculation agreed to by the same parties and will be detailed in the subsequent filing.

Rate Base

All rate base items except cash working capital would be established as "five-point" (i.e., each of the last five quarter end balances) average. Attachment 1 provides definitions for proposed rate base accounts. The electric retail jurisdictional rate base amounts are calculated by applying respective total balance to various allocation factors for each rate base item. These allocation factors are defined in Attachment 2 and will be calculated based on amounts at the beginning of the period (i.e., December 31st of the prior year).

Cash working capital is determined using the Company's most recent lead/lag study, as approved in the last general rate review. The recorded and adjusted costs will only be updated annually based on financial information from the FERC Form 1, except for federal income taxes and interest expense which will be updated each quarter. The federal income tax lag days will be adjusted to reflect quarterly payments using 37.5 lag days. This approach is outlined in Attachment 1B.

Income taxes are adjusted to remove the tax on non-rate base and FERC jurisdiction adjustments. This approach is outlined in Attachment 1C.

Income Statement

The income statement reflects electric utility operations with revenues from sales to retail customers specifically identified. Attachment 1A provides definitions for proposed income statement accounts. Other revenues and all other operating expenses of Nevada Power are either assigned to retail electric operations using specific charges or allocated using the allocation method as summarized in Attachment 2.

Line 29 Carry on regulatory assets and liabilities – Nevada Power is allowed to record carry on certain regulatory assets and liabilities that are not yet in rates. Since these assets and liabilities are included in rate base, the associated carry needs to be included in net operating income used in the regulatory return on equity calculation.

Line 30 Lenzie incentive – In Docket No. 04-6030, the PUCN designated the Lenzie units as a "critical facility" and eligible for an enhanced return on equity of 2.5% above the authorized return on equity. The amount allowed in the last rate case is removed from net operating income in order to calculate the return without the Lenzie incentive.

Line 31 Tax on Line 30 calculates tax on line 30 at the federal tax rate.

Other than the adjustments described above, no other pro forma adjustments would be proposed to be made.

Cost of Capital

The capital structure used will be based on a five-point quarterly average for the period being reported. The cost of debt is calculated using the 12-month rolling expense per the income statement and the five point quarterly average for debt balance sheet items. Attachment 1D provides definitions for proposed rate base accounts. The calculation will be modified based on the last approved general rate review.

Earnings Sharing

The December 29, 2018 PUCN order on Docket Nos 17-06003 and 17-06004 established a regulatory requirement for Nevada Power to share with customers earnings that exceed a 9.7% return on equity threshold. For purposes of calculating earnings sharing, the following adjustments will be made to net operating income used in the regulatory return on equity calculation:

Line 53 Plus accrual for sharing – This line reverses, for purpose of this calculation, any current period accruals the Company has made in anticipation of earnings sharing pursuant to the terms of Docket 17-06003.

Line 54 Plus long-term incentive plan accrual – Any accruals the Company has made for long-term incentive plan payments for the current year will be excluded or included (no adjustment) based on the treatment in the last approved general rate review.

Attachment 1

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Rate Base

I.		**Rate Base**	**Account/FERC Form 1 Page**	
1		Utility Plant		
	a	Utility Plant in Service	101-106, 114 less ln. 1b, 1c, 1d[1]	include
	b	Electric Plant Held for Future Use	105, 116 p.110 ln. 35	exclude
	c	Capital Leases	p. 200 ln. 4	exclude
	d	Asset Retirement Obligation	p. 204 ln. 15, 44, 74, 98	exclude
2		Construction Work in Progress	107	exclude
3		(Less) Accum Prov Depreciation		
	a	Utility Plant in Service	108, 111, 115 less ln 3b, 3c	include
	b	Electric Plant Held for Future Use	p. 200 ln. 30	exclude
	c	Asset Retirement Obligation	footnote (Schedule C)	exclude
4		Other Property and Investments	121, 123-129, 175-176 long-term	exclude
5		Working Capital		
	a	Fuel Stock	151-152	include
	b	Materials and Supplies	154, 163	include
	c	Prepayments	165	include
	d	Cash Working Capital – Assets	130-143, 145-146, 173,175-176 current	Attach 1B
	e	Cash Working Capital – Liabilities	231-239, 241	Attach 1B
6		(Less) Accumulated Uncollectibles	144	include
7		Regulatory Assets	182.3	
	a	Included in Nevada retail rate base	p. 232	include
	b	Excluded in Nevada retail rate base	p. 232	exclude
	c	Other recovery method – balancing accounts	p. 232	exclude
	d	GAAP	p. 232	exclude
	e	Tax	p. 232	include
8		Miscellaneous Deferred Debits	186	
	a	Included in Nevada retail rate base	p. 233	include
	b	Excluded in Nevada retail rate base	p. 233	exclude
	c	Asset Retirement Obligations	p. 233	exclude
	d	Other recovery method	p. 233	exclude
	e	Pension – AOCI Adjustment	Footnote (acct 211 in part)	include
9		Other Deferred Debits	181-182.2, 183-185, 187-189	exclude
10		(Less) Accum Deferred Taxes		
	a	Asset	190	Attach 1C
	b	Liability	281-283	Attach 1C
	c	Investment Tax Credit	255	include

[1] Acquisitions of major generation plant facilities that have not yet been approved in a general rate review will only be included if they were approved by the Public Utilities Commission of Nevada in an integrated resource plan.

I.		Rate Base	Account/FERC Form 1 Page	
11		Obligations Under Capital Leases	227, 243	exclude
12		(Less) Reserves	228, 242	include
13		Accumulated Provision for Rate Refunds	229	exclude
14		Derivative Instrument Liabilities	244	exclude
15		Asset Retirement Obligations	230	exclude
16		(Less) Customer Advances – Constr	252	include
17		Regulatory Liabilities	254	
	a	Included in Nevada retail rate base	p. 278	include
	b	Other recovery method – balancing accounts	p. 278	exclude
	c	GAAP	p. 278	exclude
	d	Tax	p. 278	include
	e	Current year earnings sharing accrual	p. 278	include
18		Other deferred credits	253	include
19		Unamortized Gain on Reacquired Debt	257	exclude
20		Long-Term Debt	221-226	exclude
21		Total Net Utility Rate Base		
22		Total Proprietary Capital	201-219	exclude

Notes:

1. Regulatory Assets and Liabilities are adjusted to remove items specifically excluded from rate base by regulatory order and are not expected to be requested in any future rate case, and items recovered through other recovery mechanisms.
2. Miscellaneous Deferred Debits include pension related deferrals and exclude all other items.

Attachment 1A

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Income Statement

II.		**Income Statement**	**Account**	
25		Operating Revenues	440-457	include
26		Operating Expenses:		
	a	Operations & Maintenance	500-598, 901-935	include
	b	Depreciation & Amortization	403-407	include
	c	Taxes Other than Income Taxes	408.1	include
	d	Income Taxes	409.1, 410.1-411.1	include
	e	Investment Tax Credit – Net	411.4	include
	f	Gains/Losses from Disposition of Allowances	411.8-411.9	include
27		Total Operating Expenses		
28		Operating Income Before Adjustments		
29		Carry on regulatory assets/liabilities	footnote (419006, 431006)[2] plus p. 278, ln *Equity Component Carry Charge*, col. e less col. d	
30		Lenzie incentive	Last GRC final Order	
31		Tax on Line 30	Line 30 x federal tax rate	
32		Net Operating Income		
33		Other Income	415-419.1, 421-421.1	exclude
34		Other Deductions	421.2-426.5	exclude
35		Taxes on Other Income and Deductions	408.2-411.5, 420	exclude
36		Interest Charges	427-432	exclude
37		Net Income		
38		Return on Rate Base (net operating income/adjusted net utility rate base)	Ln 32/Ln 21	

[2] Excluding carrying charges related to balancing accounts

Attachment 1B

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Cash Working Capital

Cash working capital is determined using the Company's most recent lead/lag study, as approved in the last general rate review. Costs are based on financial information from the prior year FERC Form 1, with the exception of federal income taxes and interest expense lines which are based on the 12-month rolling expense per the Income Statement. The federal income tax lag days will be adjusted to reflect quarterly payments using lag days of 37.5.

	Cash Working Capital	Account	FERC Form 1 page
1	Cost of fuel [3]	501, 547	320-323 lines 5, 63
2	Steam from other sources	503	320-323 line 7
3	Purchased power [4]	555, 565	320-323 lines 76, 96
4	Goods and services:		
a	O&M expenses	Income Statement Line 26a	
b	Less: Cost of fuel [1]	Cash Working Capital Line 1	
c	Steam from other sources	Cash Working Capital Line 2	
d	Purchased power [2]	Cash Working Capital Line 3	
e	Deferred energy, ML, REPR	557	320-323 line 78
f	EEPR expense	908020, 908030	320-323 footnote line 168
g	Uncollectibles	904	320-323 line 162
h	Labor including fuel handling	Cash Working Capital Line 5	
i	Pensions and benefits	926	320-323 line 187
j	Reg. commission exp. incl. mill tax	Cash Working Capital Line 6	
5	Labor including fuel handling	920	354-355 lines 11, 18 less 9
6	Reg. commission exp. incl. mill tax [5]	928	320-323 line 189
7	Property tax – AZ	408.1	262-263 line 23, col. i
8	Possessory interest tax [6]	408.1	262-263 line 33, col. i
9	NV franchise tax	408.1	262-263 lines 11, 12, col. i
10	Unemployment tax	408.1	262-263 line 13, col. i
11	FICA	408.1	262-263 line 3, col. i
12	NV business tax and UEC company use	408.1	262-263 line 16, 19, col. i
13	Use tax on Pcard purchases	408.1	262-263 line 18, col. i
14	NV commerce tax	408.1	262-263 line 17, col. i
15	Federal income taxes (37.5 lead days)	409.1	114-117 line 15
16	Interest expense [7]	Attachment 1D - Cost Amount line 39,40,41	
17	Total Cash Working Capital	Sum lines 1-16	

[3] Cost of fuel includes natural gas, diesel, coal and residual oil expenses and uses the natural gas lead days.
[4] Purchased power includes tolling, NSO, and transmission of electricity by others and uses the purchased power-other lead days.
[5] Regulatory commission expense including mill tax uses the mill tax expense lead days.
[6] Possessory interest tax includes tax for production and transmission and uses the production possessory interest tax expense lead days.
[7] Interest expense includes customer deposits and uses the interest expense lead days.

Attachment 1C

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Income Tax

Total reported income taxes are adjusted to remove the tax on non-rate base and FERC Jurisdiction adjustments. The rate base adjustments on line 10b are calculated as follows:

			Account/FERC Form 1 Page	
			Non-Rate Base	**FERC Jurisdiction**
1		Utility Plant		
	a	Utility Plant in Service		See Note 1
	b	Electric Plant Held for Future Use	Footnote (account 282)	
	c	Capital Leases	Adjustment * tax rate	
4		Other Property and Investments	Footnote (account 282)	
7		Regulatory Assets		
	b	Excluded in Nevada retail rate base	Adjustment less goodwill regulatory asset (p. 232) * tax rate	
	c	Other recovery method – balancing accounts	Adjustment * tax rate	
	d	GAAP	Adjustment * tax rate	
8		Miscellaneous Deferred Debits		
	a	Included in Nevada retail rate base		Adjustment * tax rate
	b	Excluded in Nevada retail rate base	Adjustment * tax rate	
	d	Other recovery method	Adjustment * tax rate	
9		Other Deferred Debits	Account 189 * tax rate	
11		Obligations Under Capital Leases	Adjustment * tax rate	
12		(Less) Reserves		Adjustment * tax rate
13		Accumulated Provision for Rate Refunds	Adjustment * tax rate	
14		Derivative Instrument Liabilities	Adjustment * tax rate	
17		Regulatory Liabilities		
	b	Other recovery method – balancing accounts	Adjustment * tax rate	
	c	GAAP	Equity Component Carry Charge (p. 278) * tax rate	

Attachment 1C (continued)

Note 1

		FERC Form 1 Page/ Rate Base Line
1	Utility Plant in Service	Footnote (account 282)
	Ratio	
2	FERC Jurisdiction –	
3	Utility Plant in Service	Rate Base line 1a
4	(Less) Accum Prov Depreciation Utility Plant in Service	Rate Base line 3a
5	Total Reported –	
6	Utility Plant in Service	Rate Base line 1a
7	(Less) Accum Prov Depreciation Utility Plant in Service	Rate Base line 3a
8	Total Ratio	Line (3+4)/(6+7)
9	FERC Jurisdiction Tax Adjustment on Utility Plant in Service	Line 1 * Line 8

Attachment 1D

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Cost of Capital

The capital structure and costs are based on a five-point quarterly average.

III.			Amount Used for Capital Structure		Ratio	Amount Used for Cost %	
			Acct	FERC Form 1		Acct	FERC Form 1
				(a)	(b)		(c)
39		Short-Term Debt	231	p. 112, line 37	line 39, col. (a) / line 43, col. (a)		
40		Customer Deposits	235	p. 112, line 41	line 40, col. (a) / line 43, col. (a)		
41		Long-Term Debt			line 41, col. (a) / line 43, col. (a)		
	a	Bonds	221	p. 112, line 18		221	p. 112, line 18
	b	(Less) Reacquired Debt	222	p. 112, line 19		222	p. 112, line 19
	c	Other Long-Term Debt	224	p. 112, line 21		224	p. 112, line 21
	d	Unamortized Premium on Long-Term Debt				225	p. 112, line 22
	e	(Less) Unamortized Discount on Long-Term Debt				226	p. 112, line 23
	f	Unamortized Debt Expense				181	p. 110, line 69
	g	Unamortized Loss on Reacquired Debt				189, 257	p. 110, line 81 p. 112, line 61
42		Common Equity			line 42, col. (a) / line 43, col. (a)		
	a	Total Proprietary Capital	201-219	p. 112, line16			
	b	Less: Accumulated Other Comprehensive Income	219	p. 112, line15			
	c	Less: Appropriated Earnings - Unbilled		p. 119, line 39			
43		Total		line 39+40+41+42			

Attachment 1D (continued)

			Acct	Cost Amount FERC Form 1	Cost %	Weighted Average Cost
				(d)	(e)	(f)
39		Short-Term Debt Interest & Fees	431600	Footnote p. 114, line 68	line 39, col. (d) / line 39, col. (a)	line 39, col. (b) * line 39, col. (e)
40		Customer Deposit Interest	Account 235 x rate [8]		line 40, col. (d) / line 40, col. (a)	line 40, col. (b) * line 40, col. (e)
41		Long-Term Debt				
	a	Interest on Long-Term Debt	427	p. 114, line 62		
	b	Amort. of Debt Disc. and Expense	428	p. 114, line 63		
	c	Amort. of Loss on Reacquired Debt	428.1	p. 114, line 64		
	d	(Less) Amort. of Premium on Debt-Credit	429	p. 114, line 62		
	e	(Less) Amort. of Gain on Reacquired Debt-Credit	429.1	p. 114, line 62		
	f	Total Cost		Sum line a-e	line 41f, col. (d) / sum of lines 41a-g, col. (c) [9]	line 41, col. (b) * line 41f, col. (e)

[8] The rate is set by the Public Utilities Commission of Nevada under NRS 704.655

[9] As adjusted for cost calculation - include premium, discount, deferred financing and unamortized loss on reacquired debt consistent with the last rate case.

Attachment 2

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Allocation Summary

The following methods are used to allocate Nevada Power Company's accounts to Nevada:

I. Rate Base	Form 1 Page/Account	Allocation Method
1a. Utility Plant in Service		
Intangible Plant	p. 204, line 5	_4 Labor - Salaries & Wages
Production Plant	p. 204, line 8-14, 37-43	_2 Production Demand (12 CP)
Transmission Plant	p. 204, line 48-56	_1 Transmission Demand (4 CP)
Distribution Plant	p. 204, line 60-73	_N Nevada Jurisdiction
General Plant	p. 204, line 86-95	_4 Labor - Salaries & Wages
Plant Acquisition Adjustments	p. 200, line 12	_4 Labor - Salaries & Wages
3a. Accumulated Provision Depreciation - Utility Plant in Service		
Intangible Plant	Acct 108, 115 footnote	_4 Labor - Salaries & Wages
Production Plant	Acct 108, 115 footnote	_2 Production Demand (12 CP)
Transmission Plant	Acct 108, 115 footnote	_1 Transmission Demand (4 CP)
Distribution Plant	Acct 108, 115 footnote	_N Nevada Jurisdiction
General Plant	Acct 108, 115 footnote	_4 Labor - Salaries & Wages
Retirement Work in Progress	Account 108	_4 Labor - Salaries & Wages
5a. Fuel Stock	Account 151, 152	_3 Energy (Output to Lines)
5b. Materials and Supplies	Account 154, 163	_6 Gross Electric Plant in Service
5c. Prepayments	Account 165	_4 Labor - Salaries & Wages
5d. Cash Working Capital		See Cash Working Capital below
8a. Miscellaneous Deferred	p. 233 Pension Related	_4 Labor - Salaries & Wages
	Other	_N Nevada Jurisdiction
10b. Accumulated Deferred		See Attachment 1C
12. Reserves		
Injuries and Damages	228.2	_6 Gross Electric Plant in Service
Pensions and Benefits	228.3	_4 Labor - Salaries & Wages

Attachment 2 (Continued)

5d. Cash Working Capital			**Allocation Method**
1	Cost of fuel		_3 Energy (Output to Lines)
2	Steam from other sources		_3 Energy (Output to Lines)
3	Purchased power		_3 Energy (Output to Lines)
4	Goods and services:		
a	O&M expenses		Income Statement Line 3
b	Less:	Cost of fuel	Cash Working Capital Line 1
c		Steam from other sources	Cash Working Capital Line 2
d		Purchased power 2	Cash Working Capital Line 3
e		Deferred energy, ML, REPR	_3 Energy (Output to Lines)
f		EEPR expense	_N Nevada Jurisdiction
g		Uncollectibles	_N Nevada Jurisdiction
h		Labor including fuel handling	Cash Working Capital Line 5
i		Pensions and benefits	_4 Labor - Salaries & Wages
j		Reg. commission exp. incl. mill tax	Cash Working Capital Line 6
5	Labor including fuel handling		_4 Labor - Salaries & Wages
6	Reg. commission exp. incl. mill tax		_N Nevada Jurisdiction
7	Property tax – AZ		_8 Net Electric Plant in Service
8	Possessory interest tax		_2 Production Demand (12 CP)
9	NV franchise tax		_N Nevada Jurisdiction
10	Unemployment tax		_4 Labor - Salaries & Wages
11	FICA		_4 Labor - Salaries & Wages
12	NV business tax and UEC company use		_N Nevada Jurisdiction
13	Use tax on Pcard purchases		_4 Labor - Salaries & Wages
14	NV commerce tax		_N Nevada Jurisdiction
15	Federal income taxes		_8 Net Electric Plant in Service
16	Interest expense		_8 Net Electric Plant in Service

Attachment 2 (Continued)

II. Income Statement	**Form 1 Page/Account**	**Allocation Method**
1. Operating Revenues		_N Nevada Jurisdiction except:
Trans Comp of Power Sales	Footnote (account 447010)	_1 Transmission Demand (4 CP)
Sales for Resale	All other 447 accounts	_3 Energy (Output to Lines)
Transmission Ancillary Service	Footnote (456120-456160)	_2 Production Demand (12 CP)
Wheeling	Footnote (account 456170)	_1 Transmission Demand (4 CP)
Long-Term Trans Wheeling	Footnote (account 456175)	_F FERC Jurisdiction
Capacity	Footnote (456180-456185)	_1 Transmission Demand (4 CP)
3. Operations and Maintenance		
Production - Operation	500, 502, 504-509 546, 548-550, 556	_2 Production Demand (12 CP)
Production - Fuel	501, 503, 547, 555, 557	_3 Energy (Output to Lines)
Production - Maintenance	510-514, 551-554	_3 Energy (Output to Lines)
Transmission	560-564, 566-573	_1 Transmission Demand (4 CP)
Transmission - Fuel	565	_3 Energy (Output to Lines)
Distribution	580-598	_N Nevada Jurisdiction
Customer and Sales	901-916	_N Nevada Jurisdiction
Administrative & General		
Salaries, Supplies, Services	920-923, 926	_4 Labor - Salaries & Wages
Prop Ins, Injuries & Damages	924-925	_6 Gross Electric Plant in
Regulatory Commission Exp	928	_N Nevada Jurisdiction
Other	929-935	_4 Labor - Salaries & Wages
4. Depreciation and Amortization		
Intangible Plant	p. 336, line 1	_4 Labor - Salaries & Wages
Production Plant	p. 336, line 2-6	_2 Production Demand (12 CP)
Transmission Plant	p. 336, line 7	_1 Transmission Demand (4 CP)
Distribution Plant	p. 336, line 8	_N Nevada Jurisdiction
General Plant	p. 336, line 10	_4 Labor - Salaries & Wages
Plant Acquisition Adjustments	p. 114, line 9	_4 Labor - Salaries & Wages
5. Taxes Other than Income	p. 262-263, col. i,	
Payroll	line 3, 4, 13	_4 Labor - Salaries & Wages
Property	line 9, 23	_8 Net Electric Plant in Service
Possessory	line 33	_2 Production Demand (12 CP)
Use tax on pcards	line 18	_4 Labor - Salaries & Wages
Other	line 10-12, 16-17, 19, 28	_N Nevada Jurisdiction
6. Income Taxes		Calculated
7. Investment Tax Credit - Net	411.4	_8 Net Electric Plant in Service

EXHIBIT NAUGHTON-DIRECT-3

NEVADA POWER COMPANY

EARNINGS SHARING CALCULATION METHODOLOGY

Proposed Changes

Revised February 2024

NEVADA POWER COMPANY

EARNINGS SHARING CALCULATION METHODOLOGY

TABLE OF CONTENTS

Nevada Power Company

Regulatory Return on Equity Calculation

Proposal

An objective of this proposal is to keep the regulatory return on equity calculation auditable and consistent with Nevada Power Company's ("Nevada Power") FERC Form 1 and Form 3Q filings. Similarly, this proposal avoids the need for the voluminous detail required for a traditional rate filing, while arriving at a calculation that is reasonable and acceptable to all parties.

The proposed calculation yields an "imputed" return. As discussed in more detail below, the Nevada Power's electric retail jurisdictional operating income (before any provision for revenue sharing for Nevada Power under the provisions of Docket No. 17-06003) is divided by the Nevada Power's electric retail jurisdiction rate base (i.e., the 5-point average of each of the last five quarter ending balances) to arrive at an actual overall rate of return on rate base. The weighted average embedded cost of capital for preferred and long-term debt are subtracted from this rate of return, with the difference divided by the Nevada Power's common equity percentage. The weighted average embedded cost of capital is based on 5-point quarterly balances. An example calculation is presented in Attachment 3. Nevada Power will submit this calculation by March 1st following the calendar or fiscal year-end. From a procedural perspective, the filing could be set as stand-alone, or potentially submitted with the annual deferred energy accounting adjustment filing.

Generally speaking, Nevada Power will provide two different electric services from the same set of assets (i.e., retail and wholesale services). Nevada Power will sell energy directly to end users, and the Nevada Retail Jurisdiction reflects the return on investment from the sale of electricity to end users located in Nevada. Nevada Power will also provide wholesale electric services; specifically, the Company sells energy to other companies that resell the energy to end users and the Company provides transmission service to customers who transport energy across the Nevada Utilities transmission system. The FERC Jurisdiction return reflects the return on investment from the sale of wholesale services. Because Nevada Power provides retail and wholesale service from a common set of assets, investment and operation and maintenance expense must be allocated between the Nevada Retail and FERC Jurisdictions.

The Company's earnings sharing mechanism methodology is the outcome of discussions between the Company, PUCN Staff and BCP. Any modifications to the return or earnings sharing calculation agreed to by the same parties and will be detailed in the subsequent filing.

The Company is proposing changes in the 2024 Annual Deferred Energy Filing. All proposed changes are in italics.

Rate Base

All rate base items except cash working capital would be established as "five-point" (i.e., each of the last five quarter end balances) average. Attachment 1 provides definitions for proposed rate base accounts. The electric retail jurisdictional rate base amounts are calculated by applying respective total balance to various allocation factors for each rate base item. These allocation factors are defined in Attachment 2 and will be calculated based on amounts at the beginning of the period (i.e., December 31st of the prior year).

Cash working capital is determined using the Company's most recent lead/lag study, as approved in the last general rate review. The recorded and adjusted costs will only be updated annually based on financial information from the FERC Form 1, except for federal income taxes and interest expense which will be updated each quarter. The federal income tax lag days will be adjusted to reflect quarterly payments using 37.5 lag days. This approach is outlined in Attachment 1B.

Income taxes are adjusted to remove the tax on non-rate base and FERC jurisdiction adjustments. This approach is outlined in Attachment 1C.

Plant items related to the Natural Disaster Protection Plan and Expanded Solar Access Program, whereas the return on and of these items are recovered through a separate recovery method, are adjusted out of Plant in Service and Provision of Accumulated Depreciation. This is referenced in Attachment 1.

Income Statement

The income statement reflects electric utility operations with revenues from sales to retail customers specifically identified. Attachment 1A provides definitions for proposed income statement accounts. Other revenues and all other operating expenses of Nevada Power are either assigned to retail electric operations using specific charges or allocated using the allocation method as summarized in Attachment 2.

Line 29 Carry on regulatory assets and liabilities – Nevada Power is allowed to record carry on certain regulatory assets and liabilities that are not yet in rates. Since these assets and liabilities are included in rate base, the associated carry needs to be included in net operating income used in the regulatory return on equity calculation.

Line 30 Lenzie incentive – In Docket No. 04-6030, the PUCN designated the Lenzie units as a "critical facility" and eligible for an enhanced return on equity of 3% above the authorized return on equity. The amount allowed in the last rate case is removed from net operating income in order to calculate the return without the Lenzie incentive.

Line 31 Tax on Line 30 calculates tax on line 30 at the federal tax rate.

Other than the adjustments described above, no other pro forma adjustments would be proposed to be made.

Cost of Capital

The capital structure used will be based on a five-point quarterly average for the period being reported. The cost of debt is calculated using the 12-month rolling expense per the income statement and the five point quarterly average for debt balance sheet items. Attachment 1D provides definitions for proposed rate base accounts. The calculation will be modified based on the last approved general rate review.

Earnings Sharing

The December 29, 2018 PUCN order on Docket Nos 17-06003 and 17-06004 established a regulatory requirement for Nevada Power to share with customers earnings that exceed a 9.7% return on equity threshold. For purposes of calculating earnings sharing, the following adjustments will be made to net operating income used in the regulatory return on equity calculation:

Line 53 Plus accrual for sharing – This line reverses, for purpose of this calculation, any current period accruals the Company has made in anticipation of earnings sharing pursuant to the terms of Docket 17-06003.

Line 54 Plus long-term incentive plan accrual – Any accruals the Company has made for long-term incentive plan payments for the current year will be excluded or included (no adjustment) based on the treatment in the last approved general rate review.

Attachment 1

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Rate Base

I.		**Rate Base**	**Account/FERC Form 1 Page**	
1		Utility Plant		
	a	Utility Plant in Service	101-106, 114 less ln. 1b, 1c, 1d[1]	include
	b	Electric Plant Held for Future Use	105, 116 p.110 ln. 35	exclude
	c	Capital Leases	p. 200 ln. 4	exclude
	d	Asset Retirement Obligation	p. 204 ln. 15, 44, 74, 98	exclude
	e	***NDPP & ESPC Plant in Service***	***101***	***exclude***
2		Construction Work in Progress	107	exclude
3		(Less) Accum Prov Depreciation		
	a	Utility Plant in Service	108, 111, 115 less ln 3b, 3c	include
	b	Electric Plant Held for Future Use	p. 200 ln. 30	exclude
	c	Asset Retirement Obligation	footnote (Schedule C)	exclude
	d	***NDPP & ESPC Accum Prov Depreciation***	***108***	***exclude***
4		Other Property and Investments	121, 123-129, 175-176 long-term	exclude
5		Working Capital		
	a	Fuel Stock	151-152	include
	b	Materials and Supplies	154, 163	include
	c	Prepayments	165	include
	d	Cash Working Capital – Assets	130-143, 145-146, 173,175-176 current	Attach 1B
	e	Cash Working Capital – Liabilities	231-239, 241	Attach 1B
6		(Less) Accumulated Uncollectibles	144	include
7		Regulatory Assets	182.3	
	a	Included in Nevada retail rate base	p. 232	include
	b	Excluded in Nevada retail rate base	p. 232	exclude
	c	Other recovery method – balancing accounts	p. 232	exclude
	d	GAAP	p. 232	exclude
	e	Tax	p. 232	include
8		Miscellaneous Deferred Debits	186	
	a	Included in Nevada retail rate base	p. 233	include
	b	Excluded in Nevada retail rate base	p. 233	exclude
	c	Asset Retirement Obligations	p. 233	exclude
	d	Other recovery method	p. 233	exclude
	e	Pension – AOCI Adjustment	Footnote (acct 211 in part)	include
9		Other Deferred Debits	181-182.2, 183-185, 187-189	exclude
10		(Less) Accum Deferred Taxes		

[1] Acquisitions of major generation plant facilities that have not yet been approved in a general rate review will only be included if they were approved by the Public Utilities Commission of Nevada in an integrated resource plan.

			Account/FERC Form 1 Page	
I.	**Rate Base**		**Account/FERC Form 1 Page**	
	a	Asset	190	Attach 1C
	b	Liability	281-283	Attach 1C
	c	***Investment Tax Credit***	***255***	***exclude (Note 3)***
11		Obligations Under Capital Leases	227, 243	exclude
12		(Less) Reserves	228, 242	include
13		Accumulated Provision for Rate Refunds	229	exclude
14		Derivative Instrument Liabilities	244	exclude
15		Asset Retirement Obligations	230	exclude
16		(Less) Customer Advances – Constr	252	include
17		Regulatory Liabilities	254	
	a	Included in Nevada retail rate base	p. 278	include
	b	Other recovery method – balancing accounts	p. 278	exclude
	c	GAAP	p. 278	exclude
	d	Tax	p. 278	include
	e	Current year earnings sharing accrual	p. 278	include
18		Other deferred credits	253	include
19		Unamortized Gain on Reacquired Debt	257	exclude
20		Long-Term Debt	221-226	exclude
21		Total Net Utility Rate Base		
22		Total Proprietary Capital	201-219	exclude

Notes:

1. Regulatory Assets and Liabilities are adjusted to remove items specifically excluded from rate base by regulatory order and are not expected to be requested in any future rate case, and items recovered through other recovery mechanisms.
2. Miscellaneous Deferred Debits include pension related deferrals and exclude all other items.
3. ***In 2023, it was determined that including Investment Tax Credits in rate base poses a potential normalization violation, unless related to a battery energy storage system.[2] Going forward, they will be excluded, unless an exemption exists due to the relation to a battery energy storage system.***

[2] Section 13102(f)(5) of Public Law 117–169, 136 Stat. 1818 (August 16, 2022), commonly known as the Inflation Reduction Act of 2022 ("IRA"), amended Section 50(d)(2) of the Internal Revenue Code ("Code") by adding an election out of the investment tax credit ("ITC") normalization rules for energy storage technology.

Attachment 1A

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Income Statement

II.		**Income Statement**	**Account**	
25		Operating Revenues	440-457	include
26		Operating Expenses:		
	a	Operations & Maintenance	500-598, 901-935	include
	b	Depreciation & Amortization	403-407	include
	c	Taxes Other than Income Taxes	408.1	include
	d	Income Taxes	409.1, 410.1-411.1	include
	e	Investment Tax Credit – Net	411.4	***exclude***[3]
	f	Gains/Losses from Disposition of Allowances	411.8-411.9	include
27		Total Operating Expenses		
28		Operating Income Before Adjustments		
29		Carry on regulatory assets/liabilities	footnote (419006, 431006)[4] plus p. 278, ln Equity Component Carry Charge**,** col. e less col. d	
30		Lenzie incentive	Last GRC final Order	
31		Tax on Line 30	Line 30 x federal tax rate	
32		Net Operating Income		
33		Other Income	415-419.1, 421-421.1	exclude
34		Other Deductions	421.2-426.5	exclude
35		Taxes on Other Income and Deductions	408.2-411.5, 420	exclude
36		Interest Charges	427-432	exclude
37		Net Income		
38		Return on Rate Base (net operating income/adjusted net utility rate base)	Ln 32/Ln 21	

[3] ***Except as exempt as discussed in Note 3 above***
[4] Excluding carrying charges related to balancing accounts**, *this includes NDPP and ESPC.***

Revised February 2024

Attachment 1B

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Cash Working Capital

Cash working capital is determined using the Company's most recent lead/lag study, as approved in the last general rate review. Costs are based on financial information from the prior year FERC Form 1, with the exception of federal income taxes and interest expense lines which are based on the 12-month rolling expense per the Income Statement. The federal income tax lag days will be adjusted to reflect quarterly payments using lag days of 37.5.

	Cash Working Capital	Account	FERC Form 1 page
1	Cost of fuel [5]	501, 547	320-323 lines 5, 63
2	Steam from other sources	503	320-323 line 7
3	Purchased power [6]	555, 565	320-323 lines 76, 96
4	Goods and services:		
a	O&M expenses	Income Statement Line 26a	
b	Less: Cost of fuel [1]	Cash Working Capital Line 1	
c	Steam from other sources	Cash Working Capital Line 2	
d	Purchased power [2]	Cash Working Capital Line 3	
e	Deferred energy, ML, REPR	557	320-323 line 78
f	EEPR expense	908020, 908030	320-323 footnote line 168
g	Uncollectibles	904	320-323 line 162
h	Labor including fuel handling	Cash Working Capital Line 5	
i	Pensions and benefits	926	320-323 line 187
j	Reg. commission exp. incl. mill tax	Cash Working Capital Line 6	
5	Labor including fuel handling	920	354-355 lines 11, 18 less 9
6	Reg. commission exp. incl. mill tax [7]	928	320-323 line 189
7	Property tax – AZ	408.1	262-263 line 23, col. i
8	Possessory interest tax [8]	408.1	262-263 line 33, col. i
9	NV franchise tax	408.1	262-263 lines 11, 12, col. i
10	Unemployment tax	408.1	262-263 line 13, col. i
11	FICA	408.1	262-263 line 3, col. i
12	NV business tax and UEC company use	408.1	262-263 line 16, 19, col. i
13	Use tax on Pcard purchases	408.1	262-263 line 18, col. i
14	NV commerce tax	408.1	262-263 line 17, col. i
15	Federal income taxes (37.5 lead days)	409.1	114-117 line 15
16	Interest expense [9]	Attachment 1D - Cost Amount line 39,40,41	
17	Total Cash Working Capital	Sum lines 1-16	

[5] Cost of fuel includes natural gas, diesel, coal and residual oil expenses and uses the natural gas lead days.
[6] Purchased power includes tolling, NSO, and transmission of electricity by others and uses the purchased power-other lead days.
[7] Regulatory commission expense including mill tax uses the mill tax expense lead days.
[8] Possessory interest tax includes tax for production and transmission and uses the production possessory interest tax expense lead days.
[9] Interest expense includes customer deposits and uses the interest expense lead days.

Attachment 1C

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Income Tax

Total reported income taxes are adjusted to remove the tax on non-rate base and FERC Jurisdiction adjustments. The rate base adjustments on line 10b are calculated as follows:

			Account/FERC Form 1 Page	
			Non-Rate Base	**FERC Jurisdiction**
1		Utility Plant		
	a	Utility Plant in Service		See Note 1
	b	Electric Plant Held for Future Use	Footnote (account 282)	
	c	Capital Leases	Adjustment * tax rate	
4		Other Property and Investments	Footnote (account 282)	
7		Regulatory Assets		
	b	Excluded in Nevada retail rate base	Adjustment less goodwill regulatory asset (p. 232) * tax rate	
	c	Other recovery method – balancing accounts	Adjustment * tax rate	
	d	GAAP	Adjustment * tax rate	
8		Miscellaneous Deferred Debits		
	a	Included in Nevada retail rate base		Adjustment * tax rate
	b	Excluded in Nevada retail rate base	Adjustment * tax rate	
	d	Other recovery method	Adjustment * tax rate	
9		Other Deferred Debits	Account 189 * tax rate	
11		Obligations Under Capital Leases	Adjustment * tax rate	
12		(Less) Reserves		Adjustment * tax rate
13		Accumulated Provision for Rate Refunds	Adjustment * tax rate	
14		Derivative Instrument Liabilities	Adjustment * tax rate	
17		Regulatory Liabilities		
	b	Other recovery method – balancing accounts	Adjustment * tax rate	
	c	GAAP	Equity Component Carry Charge (p. 278) * tax rate	

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Attachment 1C (continued)

Note 1

		FERC Form 1 Page/ Rate Base Line
1	Utility Plant in Service	Footnote (account 282)
	Ratio	
2	FERC Jurisdiction –	
3	Utility Plant in Service	Rate Base line 1a
4	(Less) Accum Prov Depreciation Utility Plant in Service	Rate Base line 3a
5	Total Reported –	
6	Utility Plant in Service	Rate Base line 1a
7	(Less) Accum Prov Depreciation Utility Plant in Service	Rate Base line 3a
8	Total Ratio	Line (3+4)/(6+7)
9	FERC Jurisdiction Tax Adjustment on Utility Plant in Service	Line 1 * Line 8

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Attachment 1D

NEVADA POWER COMPANY
Regulatory Return on Equity Calculation
Line Item Definition – Cost of Capital

The capital structure and costs are based on a five-point quarterly average.

III.			**Amount Used for Capital Structure**		**Ratio**	**Amount Used for Cost %**	
			Acct	**FERC Form 1**		**Acct**	**FERC Form 1**
				(a)	**(b)**		**(c)**
39		Short-Term Debt	231	p. 112, line 37	line 39, col. (a) / line 43, col. (a)		
40		Customer Deposits	235	p. 112, line 41	line 40, col. (a) / line 43, col. (a)		
41		Long-Term Debt			line 41, col. (a) / line 43, col. (a)		
	a	Bonds	221	p. 112, line 18		221	p. 112, line 18
	b	(Less) Reacquired Debt	222	p. 112, line 19		222	p. 112, line 19
	c	Other Long-Term Debt	224	p. 112, line 21		224	p. 112, line 21
	d	Unamortized Premium on Long-Term Debt				225	p. 112, line 22
	e	(Less) Unamortized Discount on Long-Term Debt				226	p. 112, line 23
	f	Unamortized Debt Expense				181	p. 110, line 69
	g	Unamortized Loss on Reacquired Debt				189, 257	p. 110, line 81 p. 112, line 61
42		Common Equity			line 42, col. (a) / line 43, col. (a)		
	a	Total Proprietary Capital	201-219	p. 112, line16			
	b	Less: Accumulated Other Comprehensive Income	219	p. 112, line15			
	c	Less: Appropriated Earnings - Unbilled		p. 119, line 39			
43		Total		line 39+40+41+42			

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Attachment 1D (continued)

			Cost Amount		Cost %	Weighted Average Cost
		Acct	FERC Form 1			
			(d)		(e)	(f)
39	Short-Term Debt Interest & Fees	431600	Footnote p. 114, line 68		line 39, col. (d) / line 39, col. (a)	line 39, col. (b) * line 39, col. (e)
40	Customer Deposit Interest	Account 235 x rate [10]			line 40, col. (d) / line 40, col. (a)	line 40, col. (b) * line 40, col. (e)
41	Long-Term Debt					
a	Interest on Long-Term Debt	427	p. 114, line 62			
b	Amort. of Debt Disc. and Expense	428	p. 114, line 63			
c	Amort. of Loss on Reacquired Debt	428.1	p. 114, line 64			
d	(Less) Amort. of Premium on Debt-Credit	429	p. 114, line 62			
e	(Less) Amort. of Gain on Reacquired Debt-Credit	429.1	p. 114, line 62			
f	Total Cost	Sum line a-e			line 41f, col. (d) / sum of lines 41a-g, col. (c) [11]	line 41, col. (b) * line 41f, col. (e)

[10] The rate is set by the Public Utilities Commission of Nevada under NRS 704.655.
[11] As adjusted for cost calculation - include premium, discount, deferred financing and unamortized loss on reacquired debt consistent with the last rate case.

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Attachment 2

NEVADA POWER COMPANY

**Regulatory Return on Equity Calculation
Allocation Summary**

The following methods are used to allocate Nevada Power Company's accounts to Nevada:

I. Rate Base	**Form 1 Page/Account**	**Allocation Method**
1a. Utility Plant in Service		
Intangible Plant	p. 204, line 5	_4 Labor - Salaries & Wages
Production Plant	p. 204, line 8-14, 37-43	_2 Production Demand (12 CP)
Transmission Plant	p. 204, line 48-56	_1 Transmission Demand (4 CP)
Distribution Plant	p. 204, line 60-73	_N Nevada Jurisdiction
General Plant	p. 204, line 86-95	_4 Labor - Salaries & Wages
Plant Acquisition Adjustments	p. 200, line 12	_4 Labor - Salaries & Wages
3a. Accumulated Provision Depreciation - Utility Plant in Service		
Intangible Plant	Acct 108, 115 footnote	_4 Labor - Salaries & Wages
Production Plant	Acct 108, 115 footnote	_2 Production Demand (12 CP)
Transmission Plant	Acct 108, 115 footnote	_1 Transmission Demand (4 CP)
Distribution Plant	Acct 108, 115 footnote	_N Nevada Jurisdiction
General Plant	Acct 108, 115 footnote	_4 Labor - Salaries & Wages
Retirement Work in Progress	Account 108	_4 Labor - Salaries & Wages
5a. Fuel Stock	Account 151, 152	_3 Energy (Output to Lines)
5b. Materials and Supplies	Account 154, 163	_6 Gross Electric Plant in Service
5c. Prepayments	Account 165	_4 Labor - Salaries & Wages
5d. Cash Working Capital		See Cash Working Capital below
8a. Miscellaneous Deferred	p. 233 Pension Related	_4 Labor - Salaries & Wages
	Other	_N Nevada Jurisdiction
10b. Accumulated Deferred		See Attachment 1C
12. Reserves		
Injuries and Damages	228.2	_6 Gross Electric Plant in Service
Pensions and Benefits	228.3	_4 Labor - Salaries & Wages

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Attachment 2 (Continued)

5d. Cash Working Capital			**Allocation Method**
1		Cost of fuel	_3 Energy (Output to Lines)
2		Steam from other sources	_3 Energy (Output to Lines)
3		Purchased power	_3 Energy (Output to Lines)
4		Goods and services:	
	a	O&M expenses	Income Statement Line 3
	b	Less: Cost of fuel	Cash Working Capital Line 1
	c	Steam from other sources	Cash Working Capital Line 2
	d	Purchased power 2	Cash Working Capital Line 3
	e	Deferred energy, ML, REPR	_3 Energy (Output to Lines)
	f	EEPR expense	_N Nevada Jurisdiction
	g	Uncollectibles	_N Nevada Jurisdiction
	h	Labor including fuel handling	Cash Working Capital Line 5
	i	Pensions and benefits	_4 Labor - Salaries & Wages
	j	Reg. commission exp. incl. mill tax	Cash Working Capital Line 6
5		Labor including fuel handling	_4 Labor - Salaries & Wages
6		Reg. commission exp. incl. mill tax	_N Nevada Jurisdiction
7		Property tax – AZ	_8 Net Electric Plant in Service
8		Possessory interest tax	_2 Production Demand (12 CP)
9		NV franchise tax	_N Nevada Jurisdiction
10		Unemployment tax	_4 Labor - Salaries & Wages
11		FICA	_4 Labor - Salaries & Wages
12		NV business tax and UEC company use	_N Nevada Jurisdiction
13		Use tax on Pcard purchases	_4 Labor - Salaries & Wages
14		NV commerce tax	_N Nevada Jurisdiction
15		Federal income taxes	_8 Net Electric Plant in Service
16		Interest expense	_8 Net Electric Plant in Service

Attachment 2 (Continued)

II. Income Statement	Form 1 Page/Account	Allocation Method
1. Operating Revenues		_N Nevada Jurisdiction except:
Trans Comp of Power Sales	Footnote (account 447010)	_1 Transmission Demand (4 CP)
Sales for Resale	All other 447 accounts	_3 Energy (Output to Lines)
Transmission Ancillary Service	Footnote (456120-456160)	_2 Production Demand (12 CP)
Wheeling	Footnote (account 456170)	_1 Transmission Demand (4 CP)
Long-Term Trans Wheeling	Footnote (account 456175)	_F FERC Jurisdiction
Capacity	Footnote (456180-456185)	_1 Transmission Demand (4 CP)
3. Operations and Maintenance		
Production - Operation	500, 502, 504-509 546, 548-550, 556	_2 Production Demand (12 CP)
Production - Fuel	501, 503, 547, 555, 557	_3 Energy (Output to Lines)
Production - Maintenance	510-514, 551-554	_3 Energy (Output to Lines)
Transmission	560-564, 566-573	_1 Transmission Demand (4 CP)
Transmission - Fuel	565	_3 Energy (Output to Lines)
Distribution	580-598	_N Nevada Jurisdiction
Customer and Sales	901-916	_N Nevada Jurisdiction
Administrative & General		
Salaries, Supplies, Services	920-923, 926	_4 Labor - Salaries & Wages
Prop Ins, Injuries & Damages	924-925	_6 Gross Electric Plant in Service
Regulatory Commission Exp	928	_N Nevada Jurisdiction
Other	929-935	_4 Labor - Salaries & Wages
4. Depreciation and Amortization		
Intangible Plant	p. 336, line 1	_4 Labor - Salaries & Wages
Production Plant	p. 336, line 2-6	_2 Production Demand (12 CP)
Transmission Plant	p. 336, line 7	_1 Transmission Demand (4 CP)
Distribution Plant	p. 336, line 8	_N Nevada Jurisdiction
General Plant	p. 336, line 10	_4 Labor - Salaries & Wages
Plant Acquisition Adjustments	p. 114, line 9	_4 Labor - Salaries & Wages
5. Taxes Other than Income	p. 262-263, col. i,	
Payroll	line 3, 4, 13	_4 Labor - Salaries & Wages
Property	line 9, 23	_8 Net Electric Plant in Service
Possessory	line 33	_2 Production Demand (12 CP)
Use tax on pcards	line 18	_4 Labor - Salaries & Wages
Other	line 10-12, 16-17, 19, 28	_N Nevada Jurisdiction

II. Income Statement	Form 1 Page/Account	Allocation Method
6. Income Taxes		Calculated
7. Investment Tax Credit - Net	411.4	***_N Nevada Jurisdiction, when applicable***[12]

[12] ***See footnote 2.***

AFFIRMATION

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

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

Date: March 1, 2024

JENNY NAUGHTON

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

EDGAR PATINO

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Edgar Patino

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

A. My name is Edgar Patino. I am a Director of Contract Management and Special Programs, for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company" and together with Nevada Power, the "Companies"). My business address is 7155 Lindell Road, Las Vegas, Nevada, 89118. I am filing testimony on behalf of Sierra.

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

A. I have approximately 23 years of experience in the utility industry working at the Companies. My experience includes managing power purchase agreements ("PPAs") and energy supply agreements ("ESAs"), external and government affairs, process improvement, economic development and major accounts. I have a Master of Business Administration, and a Bachelor of Science in Business Management and Marketing from the University of Nevada, Las Vegas. **Exhibit Patino-Direct-1** provides a more detailed description of my educational background and industry experience.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF CONTRACT MANAGEMENT AND SPECIAL PROGRAMS.

A. As a Director of Contract Management and Special Programs, my responsibilities include the on-going management of long-term renewable and non-renewable PPAs, gas agreements, and ESAs.

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

A. Yes. I have previously provided testimony in the Companies' 2023 deferred energy proceedings in Docket Nos. 23-03005 and 23-03006.

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

A. My testimony addresses the following items where Sierra recorded costs or revenue to deferred energy during calendar year 2023 ("Deferral Period"):

- Long-term non-renewable PPAs;
- Renewable PPAs;
- NV GreenEnergy Rider ("NGR") agreements; and
- Portfolio energy credit ("PC") replacement costs for two renewable PPAs.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibit:

Exhibit Patino-Direct-1 Statement of Qualifications

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

7. Q. PLEASE LIST EACH OF THE LONG-TERM NON-RENEWABLE PPAs WHERE SIERRA RECORDED COSTS DURING THE DEFERRAL PERIOD.

A. Sierra recorded costs for one long-term non-renewable PPAs during the Deferral Period. **Table Patino-Direct-1** lists these agreements as well as the proceeding in which the Commission initially reviewed and approved each agreement.

TABLE PATINO-DIRECT-1
LONG-TERM NON-RENEWABLE PPAs

	Agreement	Docket No.
1.	Liberty-CalPeco (Emergency Backup Service Agreement)	09-12002 & 10-07003

8. Q. WERE THERE ANY CONTRACTUAL DELIVERY PERFORMANCE ISSUES WITH ANY OF THE COUNTERPARTIES LISTED IN TABLE PATINO-DIRECT-1?

A. No. There were no contractual delivery performance issues with any of the counterparties.

9. Q. PLEASE LIST EACH OF THE RENEWABLE PPAs WHERE SIERRA RECORDED COSTS DURING THE DEFERRAL PERIOD.

A. Sierra recorded costs for 26 renewable PPAs during the Deferral Period. **Table Patino-Direct-2** lists these agreements, as well as the proceeding in which the Commission initially reviewed and approved each PPA.

TABLE PATINO-DIRECT-2 - RENEWABLE PPAs		
	Agreement	**Docket No.**
1.	Battle Mountain	18-06003
2.	Beowawe	05-5010
3.	Boulder Solar II	15-11029
4.	Burdette Facility	04-08004
5.	Copper Mountain 5[1]	18-06003
6.	Dodge Flat	18-06003
7.	Eagle Shadow Mountain	18-06003
8.	Fish Springs Ranch	18-06003
9.	Galena 3	06-05040
10.	Hooper	QF-Legacy
11.	Moapa (Arrow Canyon) Solar	19-06039
12.	Nevada Solar One	02-12039
13.	North Valley	22-03024
14.	Switch Station 2	15-11029
15.	Techren II	17-02007
16.	Techren IV	17-11003
17.	Techren V	18-06003
18.	Turquoise	17-11003
19.	TCID-New Lahontan	QF-Legacy
20.	TMWA –Fleish	07-01036
21.	TMWA-Verdi	07-01036
22.	TMWA-Washoe	07-01036
23.	TMWRF-City of Sparks (PC Only)	06-04030
24.	USG San Emidio	11-08010
25.	Van Norman Mill Creek	N/A
26.	Young Brothers Kingston	N/A

[1] Sierra is not a counter party to the Copper Mountain 5, Eagle Shadow Mountain and Techren V's PPAs, however, pursuant to the Order in Docket No. 18-06003, Sierra shares the costs of these PPAs with Nevada Power.

10. Q. **WERE THERE ANY CONTRACTUAL DELIVERY PERFORMANCE ISSUES WITH ANY OF THE COUNTERPARTIES LISTED IN TABLE-PATINO-DIRECT-2?**

A. Yes. There were contractual delivery performance issues with certain counterparties during the Deferral Period. Where such occurred, Sierra enforced the applicable contractual provisions for 2023 energy delivery underperformance, including net energy replacement costs and will enforce the applicable contractual provisions for 2023 PC delivery underperformance starting in the April 2024 timeframe, after all the 2023 PCs are certified and transferred to Sierra. The resolution of 2023 PC delivery underperformance will be included in the 2025 Deferred Energy proceeding. See Q&As 12 and 13 for discussion on the resolution of 2022 PC delivery underperformance.

11. Q. **WERE THERE ANY PPAs TO WHICH SIERRA WAS EXPECTING TO RECORD COSTS OR REVENUE DURING THE DEFERRAL PERIOD THAT DID NOT MATERIALIZE?**

A. Yes. Iron Point, a 250 MW solar and 200 MW storage project did not achieve commercial operation on December 1, 2023, as contracted, and the build-transfer agreement was terminated on June 22, 2023. Further, Southern Bighorn, a 300 MW solar and 135 MW battery storage facility did not achieve commercial operation as contracted for in 2023 and was terminated on or about November 17, 2023. Therefore, Sierra did not record costs from Southern Bighorn as expected.

12. Q. IN CONNECTION WITH MANAGING THE RENEWABLE PPAs, PLEASE EXPLAIN THE RESOLUTION OF ANY 2022 PC SHORTFALLS THAT OCCURRED DURING THE DEFERRAL PERIOD.

A. Many of the renewable PPAs require payment of replacement costs to Sierra when the annual delivered amount of PCs is less than the annual contracted amount of PCs ("PC Shortfalls"). Sierra conducts the annual calculations to determine whether any PC Shortfalls exist for a given year in the April timeframe of the following year, after all the PCs are certified and transferred to Sierra (for example, the annual calculations for 2022 were conducted in spring 2023, with PC replacement costs paid shortly thereafter in 2023).

For calendar year 2022, there were two renewable PPAs that experienced PC Shortfalls requiring payment to Sierra. **Table Patino-Direct-3** shows the PC replacement costs paid to Sierra during the Deferral Period for the 2022 PC Shortfall. The recorded revenue was credited to the deferred energy account.

TABLE PATINO-DIRECT-3
PC REPLACEMENT COST PAYMENTS

	Agreement	**Total**
1	Galena 3	$8,651.44
2	Burdette Facility	$92,043.59
	Total	$100,695.03

13. Q. **DID THE INABILITY OF THOSE PARTIES DISCUSSED IN Q&A 12 TO PROVIDE THEIR ANNUAL CONTRACTED AMOUNT OF PCs IN 2022 RESULT IN ANY NONCOMPLIANCE OR OTHER REPLACEMENT COSTS FOR SIERRA?**

A. No. Sierra successfully met the 2022 renewable portfolio standard requirement. Moreover, Sierra did not purchase replacement PCs in 2023. Accordingly, Sierra's customers did not incur any additional costs during the Deferral Period.

14. Q. **DID SIERRA RECORD ANY COSTS OR REVENUE DURING THE DEFERRAL PERIOD FOR ANY NEW RENEWABLE PPAs?**

A. Yes. There was one renewable PPA that commenced generation in 2023. North Valley, a 25 MW geothermal facility achieved its commercial operation date on April 26, 2023, with Sierra making payments for energy delivered.

15. Q. **WERE THERE ANY PPA AMENDMENTS EXECUTED IN 2023?**

A. No.

16. Q. **PLEASE LIST EACH OF THE NGR AGREEMENTS WHERE SIERRA RECORDED REVENUE DURING THE DEFERRAL PERIOD.**

A. Sierra recorded revenue for five NGR agreements during the Deferral Period. **Table Patino-Direct-4** lists these agreements as well as the proceeding in which the Commission initially reviewed and approved the agreement.

TABLE PATINO-DIRECT-4 - NGR AGREEMENTS

	Agreement	Docket
1	Apple NGR Agreement re: Ft. Churchill Solar Array	13-07002
2	Apple NGR Agreement re: Boulder Solar II	15-11025
3	Switch NGR Agreement re: Switch Station 2	15-11025
4	Apple NGR Agreement re: Techren II Solar	17-02008
5	Apple NGR Agreement re: Turquoise	17-11002

17. Q. DID SIERRA HAVE ANY PPAs THAT TERMINATED IN 2023?

A. No.

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

A. Yes.

EXHIBIT PATINO-DIRECT-1

EDGAR PATINO, MBA, LSSBB
DIRECTOR, CONTRACT MANAGEMENT AND SPECIAL PROGRAMS
NV Energy, Inc
7155 Lindell Road
Las Vegas, NV 89188

Mr. Patino has been the Director of Contract Management and Special Programs of NV Energy, Inc. ("NVE") since July 2022. He has over 22 years of experience in the regulated energy industry. Mr. Patino has extensive experience in government affairs, external affairs and corporate communications. Mr. Patino has overseen negotiations for multiple municipal franchise agreements with local governments across the state of Nevada, facilitating increased operational efficiencies, favorable benefits for Company and customers, and right-of-way management for municipal governments. Additional experience has included roles in economic development, major accounts and business optimization and innovation where he led strategic and tactical level process improvements across the organization.

Employment History

NV Energy, Inc.
July 2022 to present
Director, Contract Management and Special Programs

Directs the contract management activities of energy supply agreements including, but not limited to, renewable energy, non-renewable energy, physical gas, and contracts supporting fleetwide generation facilities. Enforces compliance with contractual obligations to maximize value and mitigate risk to Company and its customers. Resolves contractual disputes, including the negotiation of settlement agreements and/or amendments.

NV Energy, Inc.
January 2021 – June 2022
Director, External Affairs

NV Energy, Inc.
March 2010 to December 2020
Manager, Local Government Affairs

NV Energy, Inc.
February 2005 to February 2010
Government Affairs Account Executive

NV Energy, Inc.

October 2001to January 2005
Media Relations Representative

NV Energy, Inc.
August 2001 to September 2001
Associate Specialist, Marketing

NV Energy, Inc.
April 2001to July 2001
Student Intern II, Senior

Education

University of Nevada Las Vegas, Las Vegas, NV
Master of Business Administration (MBA), 2008

University of Nevada Las Vegas, Las Vegas, NV
Bachelor of Science in Business Management and Marketing, 2001

College of the United States Air Force, Maxwell Air Force Base, AL
Associate in Applied Science in Airframe Repair Technology, 1996

Certification

Willamette University Atkinson Graduate School of Management, Portland, OR
Certificate in Utility Management, 2013

American Association for Lean Six Sigma Certification, Henderson, NV
Lean Six Sigma Black Belt (LSSBB), 2019-Current

AFFIRMATION

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

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

Date: March 1, 2024

EDGAR PATIN

DAMON PETTINARI

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Damon Pettinari

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

A. My name is Damon Pettinari. My current position is the Fuel & Purchase Power Manager for Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company") and Nevada Power Company d/b/a NV Energy ("Nevada Power" and, together with Sierra, the "Companies"). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of Sierra.

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

A. I have more than seven years of experience in accounting and finance. During my time with the Companies, I prepared and reviewed schedules of the Companies' activities related to rates and regulatory transactions, contributed to the preparation of required external financial reports and filings to Securities Exchange Commission ("SEC"), state jurisdictions and the Federal Energy Regulatory Commission ("FERC"), and I oversaw general accounting transactions. I also have three years of experience as an auditor in public accounting. A statement of my qualifications is provided as **Exhibit Pettinari-Direct-1**.

3. Q. **PLEASE DESCRIBE YOUR RESPONSIBILITIES AS FUEL & PURCHASE POWER MANAGER.**

A. As Fuel & Purchase Power Manager, my responsibilities include reviewing the recording and reconciliation of the Companies' fuel and purchased power costs, and the Companies' joint dispatch activity to the financial statements. Those functions include allocating the invoices associated with joint dispatch and the Energy Imbalance Market ("EIM") activity to the Companies.

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

A. No. However, I have assisted in preparation of schedules and data request responses for other dockets.

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

A. I sponsor Exhibit C, Sierra's Balance Sheet and Income Statement, as well as Exhibits E-1 and E-2, which pertain to fuel and purchased power costs.

6. Q. **ARE YOU SPONSORING ANY EXHIBITS OR APPENDICES?**

A. I am sponsoring the following Exhibits:

Exhibit Pettinari-Direct-1	Statement of Qualifications
Exhibit C	Sierra's Balance Sheet and Income Statement
Exhibits E-1 and E-2	Fuel and Purchased Power Cost

7. Q. **PLEASE BRIEFLY DESCRIBE EXHIBIT C.**

A. Exhibit C provides the balance sheet and income statement for Sierra. The exhibit documents the results of operations during the 12-months ended December 31, 2023 (the “Deferral Period”), as well as the ending financial condition of Sierra at December 31, 2023.

8. Q. PLEASE BRIEFLY DESCRIBE EXHIBITS E-1 AND E-2.

A. Exhibit E-1 provides the fuel usage and costs, by month and by generation station, for the Deferral Period. Exhibit E-2 reflects the purchased power usage and costs, by supplier, for the Deferral Period.

9. Q. WERE THERE ANY CHANGES TO THE COMPANIES’ FUEL AND PURCHASED POWER ACCOUNTING PROCESSES AFFECTING THE DEFERRAL PERIOD?

A. No. The accounting procedures for the joint dispatch agreement remain consistent with prior years. There have been no changes to the accounting procedures for participation in the California Independent System Operator (“CAISO”) EIM instituted on December 1, 2015.

10. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES ASSOCIATED WITH EIM.

A. I am responsible for reviewing the allocation of EIM costs supported by invoices between Nevada Power and Sierra.

In the Deferral Period, Sierra’s participation in the EIM generated two additional invoices related to short-term power purchases and non-native load sales. The first invoice is associated with Transmission EIM Entity Scheduling Coordinator activity (“EESC”). Please refer to Kim Whetzel’s Prepared Direct Testimony for more details on the EESC activity. The second invoice is connected to the

Participating Resource Scheduling Coordinator activity ("PRSC"). Please refer to Vernon Taylor's Prepared Direct Testimony for more details on the PRSC activity.

11. Q. DESCRIBE CAISO'S BILLING PROCESS.

A. The CAISO sends Nevada Power weekly invoices. In turn, Nevada Power pays all costs for PRSC and EESC activity. At the end of the month, the costs collected in the payable account are cleared first between the two utilities and then to various FERC accounts based on the type of charge or charge code.

12. Q. HOW ARE THE EIM INVOICES ALLOCATED BETWEEN NEVADA POWER AND SIERRA?

A. At the end of each month, all of the monthly activity from both the EESC and PRSC is verified by comparing the data to the invoiced total during the month. The activity is then allocated to Nevada Power and Sierra, respectively, using the methodology outlined in the joint dispatch agreement. EESC and the PRSC purchase activity is allocated based on the Companies' respective load percentages. For the PRSC sales, a cost-to-serve analysis is performed by the Resource Optimization team. Please refer to the Prepared Direct Testimony of Vernon Taylor for details of this analysis. The calculated cost-to-serve values are then deducted from the sale proceeds and allocated to the serving company to recover the cost to produce the power that was sold. The remaining proceeds from the sale are then allocated between the two companies based on total resource percentages.

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

A. Yes.

EXHIBIT PETTINARI-DIRECT-1

Statement of Qualifications of
Damon Pettinari
NV Energy
6100 Neil Road
Reno, NV 89511
(775) 834-4026
damon.pettinari@nvenergy.com

Mr. Pettinari has over seven years of experience in accounting and finance. He has worked for NV Energy for three years. During this time Mr. Pettinari has prepared and reviewed the Company's activities related to rates and regulatory transactions, reviewed regulatory orders, assisted with various schedules and financial statements submitted to the SEC, state jurisdictions and the FERC, and oversaw general accounting department activities. Mr. Pettinari spent over a year with another organization managing a broad range of accounting functions to ensure accurate and timely financial statements in accordance with International Financial Reporting Standards (IFRS). He has also been a senior auditor in public accounting.

PROFESSIONAL EXPERIENCE

NV Energy
2020- Present

Mr. Pettinari began working at NV Energy in November 2020 within the Rates and Regulatory department where he prepared and reviewed schedules of the Company's activities related to rates and regulatory transactions and reviewed regulatory orders. In May 2022 he transitioned to the External Financial Reporting department where he contributed to preparation of the Company's required external financial reports. He became the General Accounting Manager in January 2023 overseeing general accounting transactions associated with cash, debt, prepaids and intercompany transactions. In December 2023 he became the Fuel and Purchase Power Manager and is currently responsible for managing the team performing NV Energy's fuel & purchased power accounting activities including the preparation and review of schedules for general and deferred energy rate cases.

Argonaut Gold
2019-2020

Mr. Pettinari was a Senior Accountant of Corporate Accounting for Argonaut Gold. He performed consolidations of subsidiaries, assisted in preparing and reviewing financial statements in accordance with IFRS, maintained various schedules, reviewed subsidiaries' financial statements and reconciliations, performed variance analysis and monitored internal controls.

Grant Thornton LLP
2016-2019

Mr. Pettinari was an auditor and then a Senior auditor performing audits and reviews for privately held and publicly traded companies in multiple industries.

EDUCATION

University of Nevada, Reno
Bachelor of Science in Business Administration with a Major in Accounting.

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

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

Date: March 1, 2024

DAMON PETTINARI

SAMANTHA PREST

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Samantha Prest

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

A. My name is Samantha Prest. My current position is Pricing Specialist for Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company") and Nevada Power Company d/b/a NV Energy ("Nevada Power" and together with Sierra, the "Companies"). My primary business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of Sierra.

2. Q. DOES EXHIBIT PREST-DIRECT-1 ACCURATELY DESCRIBE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL EXPERIENCE AND CURRENT JOB RESPONSIBILITIES?

A. Yes, it does.

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

A. Yes, most recently I filed testimony in Sierra's 2024 General Rate Case ("GRC"), Docket No. 24-02026.

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

A. I support the proposed Energy Efficiency Program Rates ("EEPR") and the Energy Efficiency Implementation Rates ("EEIR"). This filing asks the Commission to reset the forward-looking (the Base EEPR and EEIR) and the backward-looking (the Amortization EEPR and EEIR) energy efficiency rates. Specifically, I sponsor the calculation of (a) the class and the total revenue requirements resulting from the implementation of Energy Efficiency and Conservation ("EE&C") programs, (b) the Base EEIR for each class designed to recover the energy efficiency implementation rate revenue requirement, and (c) the Base EEPR by class designed to recover projected EE&C program costs. Company witness Jenny Naughton supports the Amortization EEIR and EEPR rates in this filing.

My testimony relies on, as well as supports, the testimony of the following Company witnesses: i) Ms. Naughton, who sponsors Exhibit F, the Company's Earned Rate of Return ("EROR"); ii) Brian Ahlstedt, who sponsors Exhibit G, the Summary of Present and Proposed Rates; and iii) Ali Sheikh, who supports the forecasted EE&C program costs for 2024.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I sponsor the following exhibits to my testimony and the application:

- **Exhibit Prest-Direct-1** - Statement of Qualifications;
- **Exhibit J** - the Base EEPR and Base EEIR calculations; and
- **Exhibit J-1** - the 2024 class-specific sales forecasts.

6. Q. WHAT ARE THE PROPOSED BASE EEIR AND BASE EEPR?

A. The proposed 2024 Base EEPRs are found in Column (n) of Exhibit J, page 1, and the Base EEIRs are found in Column (n) of Exhibit J, page 2. Proposed tariffs reflecting the revised rates are contained in Exhibit A to the application. The Base EEIR for single-family Residential ("D-1") is \$0.00019 per kWh and the Base EEPR is \$0.00231 per kWh. Exhibit G, supported by Mr. Ahlstedt, illustrates the impact of these proposed rates by class.

7. Q. HOW DO THE EEIR AND EEPR RATES COMPARE TO THE FILING IN SIERRA'S 2023 DEFERRED ENERGY ACCOUNTING ADJUSTMENT ("DEAA") FILING, DOCKET NO. 23-03006?

A. For most classes, the total EE rate is slightly higher than the 2023 rates. This is driven by the increase to the EE&C program cost budget compared to that utilized in the 2023 DEAA filing. The single-family residential class will have a combined Base EEIR and Base EEPR of \$0.00250 per kWh, a small increase from last year's combined rate of \$0.00245 per kWh.

8. Q. WERE THERE ANY CHANGES TO THE BASE EEPR AND BASE EEIR RATE MAKING METHODOLOGY FROM THOSE ACCEPTED IN THE FILING IN DOCKET NO. 23-03006?

A. No. The overriding rate design methodologies and rate calculations are the same in this application as was approved by the Commission in Docket No. 23-03006.

9. Q. PLEASE EXPLAIN THE METHODOLOGY USED IN CALCULATING THE BASE EEIR REVENUE REQUIREMENT.

A. In Docket No. 14-10018, the Commission put into effect NAC § 704.95225, which states in pertinent part:

> 1. An electric utility may recover an amount based on measured and verifiable effects of the implementation by the electric utility of programs for energy efficiency and conservation described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility. The amount recovered must include:
>
> (a) The costs reasonably incurred by the electric utility in implementing and administering the programs for energy efficiency and conservation, which are recovered pursuant to paragraph (a) of subsection 2 of NAC 704.9523; and
>
> (b) An amount equal to the costs reasonably incurred by the electric utility in implementing and administering the programs for energy efficiency and conservation multiplied by the electric utility's authorized overall rate of return grossed up for taxes applicable to the utility's equity portion of the authorized rate of return, which is recovered pursuant to paragraph (b) of subsection 2 of NAC 704.9523. (LCB File No. R046-15, at Section 1)

Part (b) of the above excerpt defines the methodology used for calculating the amount of base energy efficiency implementation revenue being requested in this case. This method was preferred by the Commission for its ease of understanding, administering, and applying in comparison to past methods for quantifying lost revenue as a result of the Company's EE&C programs. The last approved overall EROR grossed up for taxes applicable to the Company's equity portion of the authorized EROR is 8.27 percent, which was approved in Sierra's 2022 general rate case, Docket No. 22-06014. This percentage was applied to the EE&C 2024 program budget of $15,879,503 resulting in a total implementation revenue requirement of $1,313,538. The program costs are supported by Mr. Sheikh in his Prepared Direct Testimony.

10. Q. HAS THE COMPANY CHANGED ITS METHODOLOGY FOR ALLOCATING THE BASE EEIR AND BASE EEPR REVENUE REQUIREMENT TO CUSTOMER CLASSES FROM WHAT HAS BEEN USED AND APPROVED IN PREVIOUS ENERGY EFFICIENCY RATE SETTING DOCKETS?

A. No changes were made to the overriding methodology for allocating base revenue requirements to customer classes. The total approved budgeted amount of program costs, shown in Exhibit J-2, and the calculated implementation revenue are allocated across classes using the percentage of total combined marginal costs of generation and energy from the Company's final Marginal Cost of Service Study from the most recent general rate review proceeding. For this filing, the cost-of-service study from Sierra's 2022 general rate case ("GRC") filing, Docket No. 22-06014, was used as the basis for the class allocations.

The resulting allocation of both the total Base EEIR and Base EEPR revenue requirements to each class produces a class-specific Base EEIR and Base EEPR revenue requirement. The class revenue requirements are then divided by the total sales forecast for 2024 (found in Exhibit J-1 to the filing) to obtain the initial class-specific Base EEIR and Base EEPR. As described below, some classes are derived from the rate design of the otherwise applicable classes ("OAC"). The calculation of class-specific Base EEIR and Base EEPR deals with each of these classes consistent with the treatment in the rate design process accepted in the most recent general rate review proceeding. These classes pay the same Base EEPR as their OAC. To adequately account for the sales to these classes, and the revenue to be received from each of the classes, it was necessary to allocate a revenue credit to the other rate classes. This was accomplished with an additional step in Exhibit J to adjust the allocated revenue requirement of the OAC to reflect the additional revenue (revenue credit).

Consistent with past filings, there is also a shortfall of revenue resulting from the IS-2 class to which the base rates do not apply, but which has an allocation of combined generation and energy marginal cost. The IS-2 class total rate is set annually pursuant to legislation and regulation and is, therefore, exempt from the Base EEPR and Base EEIR. The original generation and energy allocator is re-normalized by using the adjusted revenue requirement, excluding the IS-2 class, and this re-normalized allocator is used to derive the Base EEPR and Base EEIR revenue requirement. The initial base rate is used to determine the revenue credits and shortfalls to be used in calculating the adjusted class revenue requirement of the OAC, which is then divided by the forecast sales adjusted to remove the sales of the revenue credit/shortfall class(es). The resulting per-kWh rate is the final Base EEIR and Base EEPR, respectively.

11. Q. WHY ARE SOME CLASSES NOT SHOWN ON EXHIBIT J?

A. This Exhibit J is consistent with past DEAA filings approved by the Commission and follows the format and methodology used in the general rate design process. Therefore, several rate classes have Base EEPR and Base EEIR that are derived from the OAC for the optional time of use ("TOU") classes or the corresponding full requirements rate class for standby classes, as applicable. For instance, the optional residential single-family TOU class ("OD-1-TOU") is assigned the same rate as the D-1 class.

Nevada Power Company
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d/b/a NV Energy

12. Q. WHY WAS EXHIBIT L NOT FILED BY SIERRA IN THIS CASE?

A. The Commission's order in Docket No. 13-04014 restricts the Company from recovering any EEIR lost revenue adjustments that contributed to earnings that exceeded those that were authorized in a calendar year. The adoption of the regulation language in NAC § 704.9523, Section 4(b) and Section 5(a) and (b), as approved in Docket No. 14-10018 provides:

> (b) Establish a rate of credits for adjustments calculated pursuant to subparagraph (2) of paragraph (a) attributable to each class of service and which are identifiable from the information maintained in accordance with paragraph (a) of subsection 3.
> 5. Except as otherwise provided in subsection 8, an electric utility must:
> (a) Record any adjustment calculated pursuant to subparagraph (2) of paragraph (a) of subsection 4 in a subaccount of FERC Account No. 254.
> (b) Transfer any balance which remains in the subaccount of FERC Account No. 254 at the end of the amortization period to the appropriate subaccount of FERC Account No. 182.3 for the current period.

In a situation where the Company does exceed its authorized ROR, Exhibit L details the calculation of the credit rate to be received by each customer class. However, as shown in the EROR calculation in Exhibit F, sponsored by Ms. Naughton, Sierra did not exceed the authorized return, and therefore, is not required to refund the Base EEIR revenue received in 2023.

13. Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO THE COMMISSION.

A. I recommend the Commission accept the updated EEPR and EEIR rates, as outlined in my testimony and provided in Exhibit J. I make this recommendation based on the testimony included in this filing.

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

A. Yes.

EXHIBIT PREST-DIRECT-1

SAMANTHA PREST
PRICING SPECIALIST
RATES AND REGULATORY AFFAIRS
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137

Ms. Prest has been an employee of NV Energy for eight years and her time at the company has been split between her previous position as an Engineering Student Intern and her current position within the Regulatory Pricing & Economic Analysis section of the Rates & Regulatory Affairs department. Her current responsibilities are focused upon electric cost of service and rate design issues and supplementary studies in support of the Rate & Regulatory Affairs department.

Employment History

NV Energy
June 2015 to Present

Pricing Specialist, Regulatory Pricing & Economic Analysis
Senior Pricing Analyst, Regulatory Pricing & Economic Analysis
Pricing Analyst, Regulatory Pricing & Economic Analysis
Associate Pricing Analyst, Regulatory Pricing & Economic Analysis
August 2017 to Present

- Conduct research and prepare studies for internal and external presentations
- Coordinate with numerous departments to gather data for marginal cost responsibility factors, Embedded Cost of Service, and other Pricing and Economic Analysis
- Provide technical support for Company filings and other Rate & Regulatory Affairs department responsibilities
- Research and prepare responses to internal and external data requests

Student Intern, Engineering & IT
June 2015 to May 2017
Renewable Energy Programs

- Primarily responsible for compiling and analyzing NEM customer data for various internal and external data requests
- Supported outreach efforts to educate the community on renewable resource options at NVE.

Vegetation Management

- Coordinated work orders and handled invoices for NVE contractors
- Provided customer solutions regarding safety and reliability concerns as related to vegetation management.

Prior Testimony before Public Utilities Commissions
PUCN Docket Nos.: 21-03005, 21-03006, 22-03001, 22-03002, 22-06014, 23-03005, 23-03006, 23-06007 and 24-02026

Education

University of Nevada, Reno
Bachelor of Science in Chemical Engineering, May 2017

Continuing Education
Utility Finance and Accounting for Financial Professionals
Economists Inc. Utilities of the Future Rates Group

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, SAMANTHA PREST, 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: March 1, 2024

SAMANTHA PREST

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

ALI SHEIKH

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Ali Sheikh

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

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

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

A. My professional experience includes more than 13 years in the engineering, construction, and utility industries. I have held a variety of positions with the Companies since I joined Nevada Power as a project manager in 2018. The details of my background and experience are provided in **Exhibit Sheikh-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS MANAGER, INTEGRATED ENERGY SERVICES - DELIVERY OPERATIONS.

A. As Manager, Integrated Energy Services, Delivery Operations, my responsibilities include managing the overall delivery of the Companies' residential and commercial demand side management ("DSM") programs as well as the energy education and energy assessment programs and DSM customer engagement. In addition, my responsibilities include managing the delivery of the Companies' Clean Energy ("CE") Programs. I am familiar with and responsible for managing expenditures necessary to deliver the Companies' energy efficiency and conservation ("EE&C") and CE programs.

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

A. Yes, I have submitted testimony in the following proceedings before the Commission: Docket Nos. 23-03005 and 23-03006.

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

A. Pursuant to the Commission's regulations, the DSM annual plan ("DSM Plan") for EE&C program costs are recovered through base and amortization Energy Efficiency Program Rates ("EEPR"). The base and amortization EEPR are reset each year in connection with the Companies' annual deferred energy filing. In section I, I support the reasonableness of EE&C program costs that are requested for recovery in this case. In this regard, I explain that costs recorded between January 1, 2023, and December 31, 2023, (the "Deferral Period") were necessary and incurred in connection with the delivery of approved EE&C programs and were reasonable under the circumstances. In short, I justify the program costs incurred during the Deferral Period. I also sponsor and present **Exhibit J-2**, 2024 DSM Program Costs, to the Application, which provides the Company's estimated program costs for EE&C programs for program year 2024.

In Section II, I support the prudence and reasonableness of the costs included in Sierra's cumulative balance in Federal Energy Regulatory Commission ("FERC") Account No. 182.3 for the Deferral Period for the Solar Energy Systems Incentive

Program ("Solar Program"), the Lower Income Solar Energy Program ("LISEP"), Wind Energy System Demonstration Program ("Wind Program"), Waterpower Energy Systems Demonstration Program ("Water Program"), Small and Large Energy Storage Programs ("Energy Storage Programs"), and Electric Vehicle Infrastructure Demonstration ("EVID") Program, collectively the CE programs. The CE proposed program rates are combined under Schedule REPR into a single item identified as the Renewable Energy Program Rate ("REPR").

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

Exhibit Sheikh-Direct-1	Statement of Qualifications
Exhibit Sheikh-Direct-2	2023 EE&C Programs
Exhibit Sheikh-Direct-3	2023 Monthly Costs by Program
Exhibit Sheikh-Direct-4	Summary of the 2023 Budgets, Costs and Carrying Charges for each EE&C Program
Exhibit Sheikh-Direct-5	2023 DSM Cost by Category Summary
Exhibit Sheikh-Direct-6	All Clean Energy Programs Balance (January 1, 2023 – December 31, 2023)
Exhibit Sheikh-Direct-7	2023 Solar and LISEP Programs Balance
Exhibit Sheikh-Direct-7A	2023 Solar and LISEP Programs Monthly Costs Summary
Exhibit Sheikh-Direct-8	2023 Electric Vehicle Demonstration Program Balance
Exhibit Sheikh-Direct-8A	2023 Electric Vehicle Monthly Program Cost Summary
Exhibit Sheikh-Direct-9	2023 Small Energy Storage Program Balance

Exhibit Sheikh-Direct-9A	2023 Small Energy Storage Program Monthly Cost Summary
Exhibit Sheikh-Direct-10	2023 Large Energy Storage Program Balance
Exhibit Sheikh-Direct-10A	2023 Large Energy Storage Program Monthly Cost Summary
Exhibit I-2	2024 CE Program REPR Budget
Exhibit J-2	2024 DSM Program Costs

7. Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony examines the 2023 EE&C and CE program expenditures in relation to budget. It discusses the controls and processes established to ensure the costs incurred by Sierra to deliver EE&C programs and CE programs in 2023 were prudent, necessary, reasonable and appropriate. In addition, my testimony addresses the measurement and verification ("M&V") process. Accordingly, the Company should recover these costs incurred during the Deferral Period for which it is seeking recovery through this proceeding.

SECTION I: DSM PLAN COSTS FOR ENERGY EFFICIENCY PROGRAM RATES

8. Q. WHAT WAS THE APPROVED BUDGET FOR SIERRA'S EE&C PROGRAMS FOR THE DEFERRAL PERIOD?

A. In its order in the Companies' jointly filed Docket No. 22-07004, the Commission approved Sierra's 2023 Annual DSM Plan Budget of $15,299,503.[1]

[1] Docket No. 22-07004, November 14, 2022, Order at Attachment 1, Sierra DSM Table.

9. Q. PLEASE DESCRIBE SIERRA'S EE&C PROGRAMS FOR THE DEFERRAL PERIOD.

A. **Exhibit Sheikh-Direct-2** describes each EE&C program that Sierra offered customers during the Deferral Period. **Exhibit Sheikh-Direct-3** provides a break-down of the monthly recorded costs by program. **Exhibit Sheikh-Direct-4** provides a summary of the budgets, costs and carrying charges for each of the EE&C programs.

10. Q. WHAT ARE THE EEPR COSTS DURING THE DEFERRAL PERIOD FOR WHICH THE COMPANY IS REQUESTING RECOVERY ?

A. The expenditures associated with Sierra's EE&C program costs for the Deferral Period for which the Company is requesting recovery are $13,165,393 as shown in **Exhibit Sheikh-Direct-3**.

11. Q. PLEASE DESCRIBE THE NATURE OF EEPR COSTS.

A. The EE&C program costs include incentive payments to customers, payments to implementation contractors, costs for M&V services provided by the M&V contractor, costs for portfolio and program outreach and marketing, and administrative costs associated with delivering the Company's EE&C programs.

12. Q. HOW DID THE PORTFOLIO OF DSM PROGRAMS FOR PROGRAM YEAR 2023 PERFORM IN RELATION TO BUDGETS AND ENERGY SAVINGS TARGETS APPROVED BY THE COMMISSION?

A. The preliminary results for 2023, as recorded in the DSM central tracking system, indicate that Sierra is expected to achieve estimated energy savings of 53,192,051 kilowatt-hour ("kWh"). This allows the Companies to meet an estimated 0.97 percent statewide of the 2023 retail sales in savings, which were achieved with expenditures of approximately 86 percent of the 2023 budget for Sierra ($13,165,393 of $15,299,503). The M&V reports for 2023 programs are being reviewed and verified and will be available as part of the Companies' DSM Plan included in the 2024 Integrated Resource Plan ("IRP") to be filed on or before June 1, 2024.

13. Q. DID ANY OF THE PROGRAMS' EXPENDITURES EXCEED BUDGET?

A. As shown in **Exhibit Sheikh-Direct-4**, two of Sierra's programs exceeded budget.

1. Residential Equipment and Plug Load program exceeded the budget by a total of $1,677,411 (or 163 percent).
2. The Residential Low Income QAR Program exceeded the budget by $92,647 (or 9 percent).

14. Q. DID ANY OF THE PROGRAMS' EXPENDITURES COME IN UNDER BUDGET?

A. As shown in **Exhibit Sheikh-Direct-4**, 12 of Sierra's programs came in under budget.

1. Energy Education came in under budget by a total of $125,150 (or 40 percent).
2. Residential Energy Reports came under budget by a total of $123,409 (or 27 percent).
3. Energy Assessments came in under budget by a total of $84,535 (or 12 percent).
4. Program Development came in under budget by a total of $22,052 (or 6 percent).
5. Residential Code and New Construction came in under budget by a total of $673,698 (or 94 percent).

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

6. Residential Direct Install came in under budget by a total of $118,332 (or 30 percent).

7. Residential Demand Response – Manage came in under budget by a total of $94,685 (or 12 percent).

8. Residential Demand Response – Build came in under budget by a total of $145,502 (or 8 percent).

9. Commercial Demand Response – Manage came in under budget by a total of $256,225 (or 64 percent).

10. Commercial Demand Response – Build came in under budget by a total of $422,013 (or 66 percent).

11. Business Program came in under budget by a total of $1,146,5601 (or 20 percent) including a credit of $303,999 which was made to the program. The nature of this credit is explained in Q&A 22.

12. Energy Smart Schools came in under budget by a total of $318,495 (or 41 percent).

15. Q. WHAT IS THE REASON THE RESIDENTIAL EQUIPMENT AND PLUG LOADS EXCEEDED BUDGET?

A. This program was successful, and had a greater participation than anticipated, and the estimated total kwh energy savings for the program exceeded the goal by 603 percent. For reasons described in Q&A 19 below, the Company reallocated funds into the Residential Equipment and Plug Loads program from other programs to allow for increased participation.

16. Q. WHAT IS THE REASON THE RESIDENTIAL LOW-INCOME PROGRAM EXCEEDED BUDGET?

A. The Residential Low-Income Qualified Appliance Replacement Program went over its budget due to a combination of factors that underscored its importance and impact. Firstly, the program experienced a significant surge in participation from low-income multifamily organizations, leading to a much higher volume of bulk installations than initially anticipated. This increased engagement contributed to escalating the overall costs due to the sheer scale of installations required.

Furthermore, the program faced additional financial pressures from the rising costs of appliances. These increases, influenced by market dynamics, further amplified the program's expenditures, making it challenging to stay within the original budgetary allocations. Together, the unexpected increase in participant engagement and the inflation in appliance costs created a scenario where the budget had to be adjusted to meet the heightened demand and cost structures.

17. Q. WHAT IS THE REASON THE COMMERCIAL PROGRAMS LISTED IN Q&A 14 WERE UNDER BUDGET?

A. In the 2023 program year, inflation significantly influenced commercial customers' decisions to engage with various programs. The economic environment, characterized by increased costs of materials and services, posed particular challenges for business-oriented initiatives listed in Q&A 14. These conditions led to higher operational costs, impacting the affordability and feasibility of participation for business customers.

Notably, the Energy Smart Schools program and the Business Services program experienced direct impacts from these inflationary pressures. More than 202

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business projects statewide, primarily within the Business Services program, were reconsidered or postponed as businesses contended with the escalated costs. Similarly, participation in the Energy Smart Schools program was affected as the inflationary environment challenged the feasibility of undertaking capital projects. This resulted in reduced customer engagement and, consequently, lower expenditures than initially projected for these commercial programs.

18. Q. WHAT IS THE REASON THE RESIDENTIAL PROGRAMS LISTED IN Q&A 14 WERE UNDER BUDGET?

A. The residential programs identified in Q&A 14, encompassing Energy Education, Residential Energy Reports, Energy Assessments, and Residential Direct Install initiatives, recorded expenditures below the allocated budget due to lower than projected participation rates despite the Company's marketing efforts. The anticipated participation levels were not achieved, which can be attributed to various factors including, but not limited to, the awareness level of the program benefits and external economic conditions that might have influenced customers' willingness to participate.

In light of the lower utilization of funds earmarked for these programs, the Company undertook a comprehensive evaluation of the performance of all its initiatives. As detailed in Q&A 22, this evaluation highlighted certain programs that were performing above expectations in terms of engagement and impact. Consequently, in alignment with strategic objectives and to optimize the effectiveness of the Company's portfolio of initiatives, a decision was made to reallocate the unused funds from the underperforming residential programs to those that were overperforming. This reallocation strategy is consistent with the

Company's commitment to efficiently manage resources and enhance the overall success of its DSM portfolio.

19. Q. WHAT IS THE REASON DEMAND RESPONSE PROGRAMS LISTED IN Q&A 14 WERE UNDER BUDGET?

A. The allocated budget for both residential and commercial demand response programs in Sierra's service territory, as referenced in Q&A 14, was underutilized due to a mix of outcomes in participation rates. The residential demand response programs, both Manage and Build, alongside the commercial Manage program, came close to achieving the kWh savings targets, demonstrating effective management and operational success. In particular, the residential Build program exceeded expectations, showcasing exceptional engagement and impact.

However, the commercial demand response Build program experienced underutilization primarily due to significantly lower participation rates than anticipated. Despite robust marketing and outreach efforts, this particular program did not achieve the expected level of engagement, which can be attributed to a variety of factors, including possible gaps in market awareness and external economic conditions that may have influenced potential participants' decisions.

In response to this varied performance across the demand response programs, the Company conducted a comprehensive evaluation of all its initiatives, as elaborated in Q&A 22. This review reaffirmed the strategic success of most demand response programs, with the notable exception of the commercial build program. Accordingly, to align with strategic objectives and maximize the effectiveness of its portfolio, the Company decided to reallocate the surplus funds to those initiatives showing remarkable performance and engagement. This strategic reallocation is in line with the Company's commitment to efficiently manage its resources and enhance the success of its DSM portfolio, leveraging the strengths of well-performing programs to foster overall program effectiveness and impact.

20. Q. WHAT IS THE REASON THE RESIDENTIAL CODE AND NEW CONSTRUCTION PROGRAM LISTED IN Q&A 14 WAS SIGNIFICANTLY UNDER BUDGET?

A. The residential codes and new construction program came in under budget, as detailed in Q&A 14, due to its suspension on March 31, 2023, due to continued zero customer participation. This decision to pause the program resulted in the halting of all activities beyond the initial phase. Consequently, only administrative costs incurred during the setup and early operation were expended, with no further spending occurring after the program's suspension.

Because of the lack of customer participation, the Company undertook a comprehensive evaluation of the performance of the program. In order to allow for other programs to exceed targets, as highlight in Q&A 22, a decision was made to reallocate the unused funds from the underperforming residential code and new construction program to those that were overperforming. This reallocation strategy is consistent with the Company's commitment to efficiently manage resources and enhance the overall success of its DSM portfolio.

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21. Q. WHY DID THE COMPANY REALLOCATE FUNDS BETWEEN DSM PROGRAMS IN ORDER TO MEET ENERGY SAVINGS TOTALS?

A. As the Company has done in the past and been supported by the Commission[2] , the difference between the original budget and the expenditures for each program was managed by reallocating funds from the programs that were not projected to spend all their funding. The Company was able to accomplish this while spending below the approved portfolio spend and still expects to meet an estimated 0.97 percent of retail sales statewide in savings.

Historically, and in 2023, the Companies have relied on their professional judgment and experience to reallocate funding between programs, keeping the DSM collaborative informed of changes throughout the year. Going forward, the Companies will continue utilizing their professional judgment and will file a 30-day informational notice to the Commission documenting material program changes pursuant to paragraph seven in the stipulation accepted in the Commission's order in Docket No. 23-06044. Specifically, the parties agreed in the stipulation:

> The Companies shall file an informational 30-Day Notice to the Commission prior to discontinuing any program, adopting new or discontinuing existing measure categories exempting custom measures, and or changing technical assumptions or eligibility requirements. The 30-Day Notice will also provide information regarding budget implications, including reallocation of funds, for the above-mentioned program changes. Notification of program changes does not constitute Commission approval or intervener agreement.

[2] See Docket Nos. 16-07001 and 16-07007.

22. Q. WHAT WAS THE REASON FOR THE ADDITIONAL CREDIT OF $303,999 FOR THE BUSINESS SERVICES PROGRAM?

A. As shown in **Exhibit Sheikh-Direct-4**, an accounting adjustment needed to be made for a credit of $303,999 due to an accrual error. This amount was paid to customers in incentives for projects that were approved and completed in in December of 2022 but were not accrued until January 2023. The Company has shown this adjustment as a separate line item.

23. Q. ARE THERE ANY OTHER EXPENSES THAT THE COMPANY INCURRED THAT ARE INCLUDED IN THE EEPR COSTS?

A. No. There are no other expenses that the Company incurred that are included in EE program costs. The cost details for all the programs can be referenced in **Exhibit Sheikh Direct-4** and **Exhibit Sheikh Direct-5**.

24. Q. WHAT STEPS DID THE COMPANY TAKE TO ENSURE THAT COSTS RECORDED TO THE EEPR ACCOUNT WERE NECESSARY TO DELIVER EE&C PROGRAMS TO CUSTOMERS?

A. The Company's EE&C programs are managed in accordance with the process described below:

1. Commission review and approval following IRP submittal

Each program is submitted to the Commission for approval in IRP's DSM Plan filing every three years. At that time, the budget, demand and energy savings goals are established for the triennial DSM Plan.

2. Commission review and approval following Annual DSM Update Report submittal

Annually, a recap of the prior year's program results and any significant program modifications are filed with the Commission as part of the Annual DSM Update Report. The Annual DSM Update Report reviews program performance compared to the budget, energy savings and demand savings goals, and identifies strategies to improve program performance in the upcoming program year. In addition, performance measures such as the Total Resource Cost ("TRC") Test, Non-Energy Benefits Total Resource Cost ("NTRC") Test, Participant Cost Test, Ratepayer Impact Test, Utility Cost Test and the Societal Cost Test are provided.

3. Project manager assigned

Upon Commission approval in the IRP, a Sierra project manager is assigned to each program. Typically, the project manager oversees several programs. The project manager is assigned the responsibility for managing the day-to-day delivery of the program, managing budgeted and actual expenditures, ensuring that program expenditures are reasonable and appropriate and meeting program energy and demand savings goals.

4. Request for Proposal ("RFP") process to select implementation contractor

The project manager issues an RFP to select an implementation contractor for the program to obtain optimum value for customers in the delivery of the program. Following the RFP, the program is awarded to the successful bidder who then becomes the implementation contractor. The project manager works closely with the implementation contractor on program startup and issues that arise as the program is implemented. Additional program and management controls are established by executing a contract for program implementation with the implementation contractor. A purchase order is then created for contractual payments.

5. Implementation contractor assigns their project manager

Although each program is different, in general, the implementation contractor is responsible for program startup, day-to-day administration, program marketing, trade ally management and education, rebate processing and payment, data collection and data quality, invoicing, and quality assurance. Typically, the implementation contractor completes these tasks by assigning a dedicated program manager to work directly with the Company's project manager.

6. Project manager's ongoing program management

The project manager meets with the implementation contractor at least weekly and engages in daily communication, as appropriate. The project manager works with the implementation contractor to make program adjustments intended to maximize program results as design and delivery issues are identified. The project manager monitors the implementation contractor's performance against key metrics such as budget, actual spend, projected spend, energy and demand savings achieved and projected energy and demand savings. At a minimum, the project manager reviews and audits monthly data submissions and invoices for work performed. The project manager also ensures contractual terms and conditions are met. The project manager will compare the actual results against projected results and investigate and resolve any discrepancies.

7. Third-party M&V contractor reports program results throughout the year and in the M&V report

The project manager serves as interface between the M&V contractor and the implementation contractors as needed to ensure field work requirements and information requests from the M&V contractor are satisfied. The project manager works with the implementation contractor to correct issues identified or implement program improvement opportunities outlined by the M&V contractor to ensure maximum program effectiveness.

25. Q. PLEASE EXPLAIN WHY THE EE&C PROGRAM COSTS RECORDED DURING THE DEFERRAL PERIOD WERE REASONABLE.

A. As discussed in Q&A 24, multiple levels of program management and controls were employed to channel constant feedback ensuring that corrective actions were taken to maximize the programs' effectiveness and efficiency, and to validate reported program accomplishments.

26. Q. WHAT PROCEDURES DOES THE COMMISSION UTILIZE TO REVIEW AND APPROVE DSM PLANS?

A. The Commission reviews and approves EE&C programs in two separate proceedings. First, the Commission reviews and approves a DSM Plan every three years pursuant to Nevada Administrative Code ("NAC") § 704.9494. The DSM Plan contains detailed implementation plans, budgets, and a cost effectiveness analysis of the EE&C programs. The DSM Plan submitted by Sierra proposed to implement these programs over a three-year action plan period for program years 2021 through 2024 was filed in Docket No. 21-06001. As a result of this process, Sierra was granted approval by the Commission to implement a set of EE&C programs.

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Second, each year following the filing of its IRP, Sierra files an Annual DSM Update Report (*e.g.*, Docket No. 23-06044). This filing reports the actual costs and verifies energy and demand savings achieved from the EE&C programs in the most recent program year and makes recommendations regarding which programs should be continued or discontinued in the following year. In addition to reporting the prior year results, the filing describes lessons learned, changes being made to improve the programs and any adjustments to program targets. This filing is vetted and is accepted, with or without modifications, or rejected by the Commission.

27. Q. PLEASE DESCRIBE THE PROCESS USED TO M&V ENERGY SAVINGS THAT FOLLOW FROM THE IMPLEMENTATION OF EE&C PROGRAMS.

A. To ensure that its M&V objectives are met, Sierra uses a process that is based on generally accepted industry standards and procedures. This work is performed by a third-party M&V evaluation contractor with considerable experience in the field. The current M&V evaluation contractor is ADM Associates.

The purpose of M&V activities is to collect and analyze data to calculate the energy and demand savings that result from EE&C programs and measures installed at sites that participate in a Sierra EE&C program.

Typically, for each program a statistically designed sample will be selected for on-site verification of measure installation. Program participants will accumulate over time, as the program is implemented. For this reason, a systematic statistically based sampling approach is used to select sample sites as program implementation proceeds. Sample selection is spread over the entire implementation period. The sample design the M&V contractor uses for selecting program projects allows estimates of savings to be determined with a ±10 percent precision at the 90 percent confidence level for the program savings being verified.

28. Q. HAVE THE 2022 M&V REPORTS BEEN ACCEPTED BY THE COMMISSION?

A. Yes. The 2022 M&V Reports were accepted by the Commission in its order issued November 2, 2023, in Docket No. 23-06044.[3]

29. Q. WHAT INFORMATION IS SHOWN IN EXHIBIT J-2 TO THE APPLICATION?

A. **Exhibit J-2**, 2024 Demand Side Management Program Costs, shows the estimated amounts that the Company anticipates spending to implement EE&C programs in 2024. These projected expenditures are the costs that the Company reasonably expects to incur in 2024 to implement and administer the approved suite of EE&C programs that the Company offers to customers. Company witness Samantha Prest, who sponsors **Exhibit J**, uses these estimated expenditures to calculate the base EEPR and Energy Efficiency Implementation Rate ("EEIR") revenue requirements.

30. Q. WHAT IS THE SOURCE OF THE ESTIMATED PROGRAM EXPENDITURES SHOWN IN EXHIBIT J-2?

A. In its order in Docket No. 23-06044,[4] the Commission approved an Annual Plan Budget of $15,879,503. According to NAC § 704.9523(3)(b)(1), an electric utility

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[3] Docket No. 23-06044, Nov. 2, 2023, Order at p. 6, para. 2

[4] *Id*. at para. 1

will apply to the Commission to establish period specific rates. Part of the period specific rates is a prospective base program cost rate for the total cost of EE&C programs that are described in the Demand Side Plan approved by the Commission. The Company uses the budgets in **Exhibit J-2** as the source for the proposed base EEPR.

31. Q. ARE THEY ANY TOPICS THAT DO NOT FALL INTO THE PROGRAMS THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. In the following questions I will address the online marketplace, marketing and 2024 IRP planning.

32. Q. PLEASE DESCRIBE THE DSM ONLINE MARKETPLACE.

A. The PowerShift online marketplace, integral to the Companies' statewide EE&C programs, serves as a branded e-commerce platform offering energy-efficient products to residential customers.[5] It not only facilitates kWh savings but also educates consumers about energy efficiency. Utilizing advanced e-commerce technology, the marketplace provides comparison shopping, customer reviews, and various purchasing options. Additionally, it offers instant rebates and targeted promotions, including special offers for low-income customers, while employing dynamic pricing strategies to optimize program efficiency and cost-effectiveness.

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[5] Available at: https://www.nvenergy.com/save-with-powershift/smart-shop

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33. Q. PLEASE DESCRIBE THE BUDGET FOR THE ONLINE MARKETPLACE AND WHERE ITS FUNDING COMES FROM.

A. The online marketplace cost is paid by contributions from the education outreach and marketing components of all approved program budgets. The total allocated budget for the online marketplace was $140,000 for Sierra.

34. Q. WHAT DOES SIERRA DO WITH THE REVENUE GENERATED BY THE PRODUCTS SOLD ON THE ONLINE MARKETPLACE.

A. There is a revenue-share agreement with the implementation contractor, in which a percent of the previous year's product purchases excluding sales tax and shipping costs are credited back to Sierra. Sierra then applies these credits toward the software subscription costs of the online marketplace. This reduces the cost burden for all customers. The revenue-share amount for the online marketplace for the Deferral Period was approximately $97 for Sierra.

35. Q. WHAT WAS THE COMPANY SPEND FOR MARKETING AND ADVERTISING FOR THE COMPANY PORTFOLIO?

A. The Company spent a total of $479,553 in marketing and advertising to engage customers for participation and raise awareness of the PowerShift brand of products and services. These costs are allocated throughout the portfolio to each program based on the program's percentage of overall budget. The marketing costs were 3.7 percent of the overall spend for Sierra.

36. Q. PLEASE DESCRIBE THE NATURE OF THE COSTS THAT WERE RECORDED TO THE IRP PLANNING SOUTH LINE ITEM 17 IN EXHIBIT SHEIKH DIRECT-4

A. The costs include a Net-To-Gross ("NTG") study that investigated free ridership and spillover effects for all the programs. This NTG study is a requirement of the Company's DSM three-year action plan that is filed with the upcoming 2024 integrated resources plan. The data from this study is an input to the cost-benefit analysis of each program.

SECTION II: RENEWABLE PROGRAM COSTS FOR RENEWABLE ENERGY PROGRAM RATES

37. Q. PLEASE SUMMARIZE THE RENEWABLE ENERGY PROGRAMS' REGULATORY REQUIREMENTS PURSUANT TO THE NEVADA REVISED STATUTES ("NRS") CHAPTER 701B.

A. Under NRS Chapter 701B Renewable Programs, the Companies must administer the Solar Energy Systems Incentive,[6] LISEP, Electric Vehicle Infrastructure Demonstration ("EVID"), and Energy Storage programs. Pursuant to NRS Chapter 701B, the Companies may "recover its reasonable and prudent costs, including, without limitation, customer incentives, that are associated with carrying out and administering" these programs.[7] The Commission's regulations require the Companies to establish base and clearing rates to recover costs associated with the programs. Pursuant to NAC Chapter 701B, the Companies filed their most recent annual Clean Energy Annual Report with the Commission in Docket No. 24-02001.

[6] "Solar Energy Systems Incentive Program", "Solar Program" or "Solar Incentive Program" are used interchangeably.
[7] Pursuant to NRS §§ 701B.230 (4), 701B.600 (2), 701B.670 (5)(b) and 701B.860.

38. Q. HOW ARE THE REPR RATES CALCULATED?

A. The REPR rates are calculated in the same way for each renewable program. Each rate is calculated by adding: (i) a prospective rate determined by dividing the total projected cost of implementing the Commission-approved annual plan by the projected kWh for the program year, and, (ii) a clearing rate determined by dividing the cumulative balance in the relevant subaccount of FERC Account No. 182.3 at the end of the test period by the test period kWh sales. Brian Ahlstedt sponsors **Exhibit I** and the REPR calculations.

39. Q. WHAT WAS THE CUMULATIVE BALANCE IN FERC ACCOUNT 182.3 AS OF THE END OF THE DEFERRAL PERIOD FOR ALL CE PROGRAMS?

A. The cumulative balances at the end of the deferral period for all CE programs is shown below. Additional detail is contained in **Exhibits Sheikh-Direct-6 through -10A**.

1. The cumulative balance for all CE programs at the end of the Deferral Period was $5,552,934. The period began with a balance of $10,637,276 on January 1, 2023. **Exhibit Sheikh-Direct-6**, shows the derivation of the cumulative balance.
2. The cumulative balance for the Solar Program and LISEP as of December 31, 2023, was $ 3,654,237. **Exhibit Sheikh-Direct-7** shows the derivation of the cumulative balance.
3. The cumulative balance for the Small Energy Storage Program, as of December 31, 2023, was $(673,666). **Exhibit Sheikh-Direct-9**, shows the derivation of the cumulative balance.
4. The cumulative balance of the Large Energy Storage Program, as of December 31, 2023, was $(79,322). **Exhibit Sheikh-Direct-10** shows the derivation of the

cumulative balance.

5. The cumulative balance of the EVID Program as of December 31, 2023, was $2,651,684. **Exhibit Sheikh-Direct-8** shows the derivation of the cumulative balance.

40. Q. PLEASE GENERALLY DESCRIBE THE CE PROGRAMS.

A. The Solar and Wind and Water programs were closed as of June 5, 2019. The Companies closed out the Solar Program, however, some costs including incentive payments and utility and contractor costs are remaining.

LISEP provided: (a) education, training, and technical support for the contracting community; (b) information and assistance for interested and participating customers; and (c) incentives for the installation of distributed solar generation. LISEP offers incentives with the purpose of providing solar incentives to entities that receive a lower income housing tax credit ("LIHTC"), or other entities that benefit lower income customers including, without limitation, homeless shelters and low-income housing. LISEP officially ended on December 31, 2023, per NRS § 701B.005.

The Energy Storage programs were available to the Companies' customers that have previously installed a renewable energy system, plan to concurrently install new energy storage devices and renewable energy systems, or plan to install standalone energy storage devices. As directed by NRS §§ 701B.223 and 701B.226, the Companies divided the Energy Storage Programs into subcategories based on the customer type and nameplate size of energy storage devices. The two Program subcategories are Small Energy Storage Program ("SESP") and Large Energy Storage Program ("LESP"). The SESP category provides incentives to residential and non-residential customers to install energy storage devices with nameplate capacity of up to 100 kW. The LESP category is reserved for energy storage devices with a nameplate capacity between 100 kW and 1,000 kW. This program was also designed to prioritize installations that serve critical infrastructure facilities. . The Energy Storage programs stopped accepting new applications on June 30, 2023, per commission order in Docket No. 23-02001. The Company is still paying outstanding reserved incentive liabilities.

The EVID Program includes electric vehicle ("EV") charging station incentives for workplace, fleet, multi-family, public convenience, governmental and lower-income multi-family charging infrastructure; the EV Custom Grant Program; and electric school buses. The "Nevada Electric Highway" ended during the 2022 program year. Additionally, the Companies have two residential programs: the Residential EV Charging Station Incentives Program and a Lower Income EV Incentives Program. The EVID program became fully reserved in August of 2022 after which Sierra stopped accepting applications. After the program closed to new applications, Sierra began issuing conditional reservations to projects that were submitted before program closure but did not receive a regular reservation notice. If a project with a valid reservation withdrew, cancelled, or forfeited, then a project with a conditional reservation would have been converted to a valid reservation, provided that enough funds were available. On June 30, 2023, per Commission order in Docket No. 23-02001, the Companies stopped converting conditional reservations to valid reservations. The Company is still paying outstanding reserved incentive liabilities.

41. Q. WHAT WERE THE TOTAL ONGOING ADMINISTRATIVE COSTS INCLUDING THE INCENTIVE PAYOUTS ASSOCIATED WITH CE PROGRAMS DURING THE DEFERRAL PERIOD?

A. The total ongoing administrative costs including the incentive payouts associated with CE programs during the deferral period for Sierra was $3,455,866 as shown on **Exhibit Sheikh-Direct-6**.

42. Q. ARE THE INCENTIVE EXPENSES ASSOCIATED WITH CARRYING OUT AND ADMINISTERING THE CE PROGRAMS REASONABLE?

A. Yes. The incentive expenditures were based on payments and available capacities established by the Commission and the Legislature in NRS Chapter 701B. The Companies do not issue an incentive payment until the project information is verified; namely, that the system has been installed according to legislation, regulations, and program rules. The Companies' operations staff may inspect the system allowing it to be connected and energized prior to payment of incentive. Monthly reports were posted to the Companies' website that contain program data and outreach information.

Compliance verification begins during the review of the application. An application selected for participation is reviewed to ensure compliance with the application requirements contained in the Net Metering and Energy Storage Device Interconnection Program handbook. When an incentive claim package is submitted, another review is conducted against all the information in the claim form and contained in all the accompanying documents, to confirm compliance with Solar Program rules and statutory and regulatory requirements.

Finally, the Companies conduct a net metering verification on-site to ensure compliance with the Companies' interconnection standards. Only when a project passes all reviews and all inspections is that project eligible to receive the incentive payment.

For the LISEP, the project management and implementation costs were also prudently incurred. The LISEP implementation expenditures were managed both by the Companies' internal staff and an outside implementation contractor. Routine project oversight was conducted at all of the sites and 100 percent of the projects were inspected by the Companies' personnel.

For the Solar and Energy Storage Programs, the implementation contractor conducted the primary administrative services including application and incentive processing, handled incoming and outgoing calls, emails, outreach services, and education and training.

43. Q. ARE THE CE PROGRAM COSTS FOR THE CURRENT PERIOD ASSOCIATED WITH CARRYING OUT AND ADMINISTERING PROGRAMS REASONABLE?

A. Yes. The CE program costs are over budget by 29 percent ($227,653 of $764,940) according to **Exhibit Sheikh-Direct-6**. These costs include implementation contractor expenses, marketing expenses, training and education expenses, and the utility administration costs which are all reasonable and within the scope of the CE annual plans approved by the Commission. The expenses were incurred under the contract between the Companies, the implementation contractor, and the application portal software provider, and were deemed necessary and reasonable for the benefit of program participants.

44. Q. WHAT ARE THE TOTAL PROJECTED CE PROGRAMS INCENTIVE PAYMENTS AND ADMINISTRATIVE BUDGETS BASED UPON THE PLAN FILED IN DOCKET NO. 24-02001?

A. The projected CE programs incentive payments and administrative budgets for 2024/2025 are $2,922,418 for Nevada Power and $1,982,713 for Sierra, for a total of $4,905,132. The proposed admin budget for the programs is $456,906, with Nevada Power accounting for 60 percent and Sierra accounting for 40 percent. The total proposed CE admin budget has decreased by 57 percent ($599,948) compared to the 2022/2023 program year.

45. Q. ARE THERE ANY FURTHER ADJUSTMENTS MADE POST 2022 WHICH IMPACTED THE TOTAL CE PROGRAM ADMIN COSTS?

A. Yes, a credit of ($39,867) for Marketing Costs is shown in **Exhibit Sheikh-Direct-6** and **Exhibit Sheikh-Direct-8**. This includes $9,883 of marketing and community outreach costs plus the adjusted amount ($49,750) of the EV survey that was erroneously charged to the regulatory asset 182303. Please see my testimony in Docket No. 23-03006 for more information about this EV survey charge. The ($49,750) adjustment was made in January 2023. In addition, the projected spending submitted to calculate the REPR in this filing was adjusted to exclude the $49,750. Therefore, the Company will not recover the EV survey cost through the REPR.

46. Q. WHAT INFORMATION IS SHOWN IN EXHIBIT I-2 TO THE APPLICATION?

A. **Exhibit I-2,** 2023 Clean Energy Program Costs, shows the estimated amounts that the Company anticipates spending to implement CE programs in 2024. These projected expenditures are the costs that the Company reasonably expects to incur in 2024 to implement and administer the CE programs that the Company offers to customers. Mr. Ahlstedt, who sponsors **Exhibit I,** uses these estimated expenditures to calculate the base REPR.

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

A. Yes.

EXHIBIT SHEIKH-DIRECT-1

Ali R. Sheikh
Manager, Demand Side Management Program Delivery
Energy Efficiency and Conservation
NV Energy
6226 W Sahara Ave
Las Vegas, NV 89146

Summary of Qualifications

Ali manages the Integrated Energy Services ("IES") at NV Energy, where he oversees a team of Program Managers responsible for delivering energy efficiency, demand response, and conservation programs. With over 10 years of experience in design, procurement, logistics, and construction, Ali is a seasoned expert in renewable energy projects, including electric vehicle charging infrastructure, utility-scale solar, and energy storage systems.

Professional Experience

Manager, IES, Delivery Operations *(2022-Current)*
Responsible for delivery of all Demand Side Management ("DSM") programs.
- Managed a team of program managers in charge of delivery of all DSM programs,
- Participated in regulatory proceedings and prepared testimonies,
- Prepared strategies for DSM programs in collaboration with various stakeholders,
- Prepared and managed the department budget, cashflow and energy savings goals.

Project Manager, NV Energy's Clean Energy Department *(2018-2022)*
Responsible for delivery of all Electric Vehicle programs
- Designed, and managed the construction of Nevada Electric Highway program,
- Managed daily activities for all Clean Energy's Electric Vehicle programs,
- Orchestrated and managed multiple Ride and Drive events for NV Energy,
- Participated in reviews and commentaries on proposed legislative and regulatory programs and bills,
- Participated in development of Economy Recovery Transportation Electrification process design.

Sr. Project Manager, Engie Storage (2018-2018)
Responsible for multiple commercial scale battery storage projects
- Managed multiple commercial scale battery storage projects with clints such as Kaiser Permanente and Visa.

Project Controls Analyst Lead – Cupertino Electric (2013-2018)
Participated in construction of various utility scale solar and utility distribution projects.
- Managed program level activities including process, cost, schedule, and technology implementation,
- Lead and managed engineering, procurement, construction, commissioning, and closeout activities,
- Interfaced with different program stakeholders including clients, subcontractors, and vendors.

Project Manager, SolarWorld Americas LLC (2011-2013)
Responsible for delivery of multiple utility scale solar projects.
- Managed more than $77 million worth of utility scale solar projects.
- Managed design and procurement of projects in Puerto Rico, US Virgin Islands and Brazil.

Education

University of California Los Angeles (UCLA)
Master of Science in Structural Mechanics, 3.71 GPA
California State University, Northridge (CSUN)
Bachelor of Science in Civil Engineering, Magna Cum Laude, 3.8 GPA

EXHIBIT SHEIKH-DIRECT-2

Nevada Power Company
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2023 Demand Side Management Programs and Budgets

Line No.	Program Title	Program Description	Budget [1]
1	Energy Education	The program is designed to educate and assist customers, builders, contractors, realtors, and energy professionals regarding the efficient use of electricity in their homes and businesses. Where possible, the program seeks to partner with community stakeholders to increase the value offered to customers by leveraging program resources. There are three components within the Energy Education Program: Residential Customer Education; Commercial Customer Education; and Low Income Energy Saving Kits.	$ 450,000
2	Residential Energy Reports	The program provides periodic energy usage reports to residential customers to inform and motivate them to take actions to save energy by using electricity more efficiently and to drive participation in other DSM programs.	$ 898,040
3	Energy Assessments	The program provides in home energy analysis and responds to customers who want to learn more about their energy use, the way their home uses energy, or how they can save money by improving the performance of their home and electrical equipment. The program is comprised of two services; online assessment and assessment conducted in the home by a certified energy consultant or energy advisor. The overall goal of this program is to educate customers about wise energy use and choices, and assist them in taking action to reduce energy consumption and lower energy bills.	$ 1,946,960
4	Program Development	Program Development focuses on the assessment and testing of innovative demand side management and program delivery models. The program may span residential, commercial, industrial, or agricultural customer segments and aims to identify new methods to increase customer satisfaction and realize energy and demand savings through delivering energy services to customers that improve energy efficiency and enable demand response in an integrated offering when possible. The program focuses on exploring new possibilities for successful demand side management strategies and conducting small scale tests of emerging products or services that may enhance current programs or address new customer segments. These trials enable the evaluation of potential customer offerings.	$ 700,000
5	Residential Equipment & Plug Loads	The Residential Equipment and Plug Load Program is an incentive program that targets residential end users with the highest energy consumption per square foot and those expected to significantly increase their energy consumption per square foot with additional energy loads, including cooling and heating, appliances, electronics, and pool pumps. This program includes both residential pool pump program and residential AC components, which were previously implemented as separate programs. This provides customers with choices and more opportunities for participation. The program will employ multiple delivery channels throughout the program cycle. The program launched in 2022.	$ 6,100,000
6	Residential Codes & New Construction	The Residential Codes and New Construction Program provides support to the residential new construction market to increase the energy efficiency of Nevada homes. Residential customers benefit through lower energy bills, increased comfort, fewer maintenance concerns, and higher resale values. The Program will have two separate but complementary components, New Construction and Residential Codes. For the New Construction component, builders of single-family and multi-family homes with four units or less will receive education, technical assistance, and incentives to exceed local building energy codes. The Program launched for the first time in 2022.	$ 1,300,000

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2023 Demand Side Management Programs and Budgets

Line No.	Program Title	Program Description	Budget [1]	
7	Residential Direct Install	The program provides residential customers with direct installation of low-cost energy efficient measures in their homes. The installation of the measures is performed by a trained and certified PowerShift Energy Advisor and will further enhance the value proposition when implemented in combination with energy assessments and smart thermostat offerings. The Program promotes potential cost savings when customers are introduced to energy efficient measures and educated on implementing these low-cost measures.	$	740,000
8	Residential Low Income QAR	The Program is designed to provide energy efficient appliances and products to low or limited income customers who experience high energy bills due to the costs of operating old and inefficient appliances. The Program will work in collaboration with state and local agencies, including the Southern Nevada Housing Authority, state weatherization programs and other agencies serving this market sector to develop delivery mechanisms to reach customers quickly and directly. The Program will leverage weatherization services another services that state agencies currently provide.	$	3,375,000
9	Residential Demand Response - Manage	The goal of Program is to serve those customers who have enrolled in the Program in all prior years, regardless of the technology that was deployed to enable them to participate. This Program works to retain and service customers, maintain the magnitude of the capacity installed in prior years, and execute a wide range of demand response business processes such as event forecasting, optimization, and execution.	$	7,800,000
10	Residential Demand Response - Build	The goal of the Program is to expand the capacity of the residential programs by recruiting additional residential customers to participate in the demand response Program and to support the customers recruited in that year to the end of the program year. For program year 2021, the Program includes only the customers who were added to the demand response system between January 1, 2021 and December 31, 2021 and the associated costs, demand savings, and energy savings. The Program enables the Company to track and analyze the costs and benefits of adding new customers and capacity to the demand response system each year.	$	7,797,800
11	Commercial Demand Response - Manage	The goal of the Program is to serve those commercial customers with completed enrollments in the Program in all prior years, regardless of the technology that was deployed to enable them to participate. This Program works to retain customers and maintain the magnitude of the capacity installed in prior years. The Program will provide ongoing program services for all customers who enrolled in the demand program in prior years.	$	900,000
12	Commercial Demand Response - Build	The Program goal is to increase the capacity of commercial programs by recruiting customers to participate in demand response and to support customers recruited during the program year. The program year includes only customers recruited during DEAA Program Year, that were added to the demand response system between January 01, 2023, and December 31, 2023, and the associated costs, demand savings, and energy savings. The Program enables the Company to track and analyze costs and benefits of new customers and capacity to the demand response system.	$	743,701

Nevada Power Company
d/b/a NV Energy
2023 Demand Side Management Programs and Budgets

Line No.	Program Title	Program Description	Budget [1]	
13	Business Program	The Program facilitates the implementation of energy efficient measures for both existing and new commercial, industrial and institutional customers through incentives and comprehensive technical services. The program offers incentives for measures such as energy efficient lighting, cooling, motors, pumps, commercial kitchens and refrigeration and miscellaneous energy conservation measures. The Program's Non-Profit Agency Sheikh component offers qualifying non-profit organizations a financial means to implement energy efficiency measures. This component provides financial assistance in the form of rebates and technical support to non-profit organizations for the identification and installation of energy efficiency measures in new or existing buildings. To qualify, an agency must be a 501(c)3 entity located within the Company's service territory.	$	14,000,000
14	Energy Smart Schools	The Program is designed to facilitate energy efficiency and peak demand reduction in public schools, including K-12 and schools of higher education. The Program offers two types of energy services to school administrators. First, rebates help offset a portion of the first cost associated with efficiency investments for energy efficiency projects. Second, the Program provides a high level of technical assistance that serves to offset the staffing needs for school facility management that would be required for administering energy efficiency projects.	$	1,350,000
15	**TOTAL PROGRAM COSTS**		**$**	**48,101,501**

[1] Docket No. 22-07004, November 14, 2022, Order at Attachment 1, Nevada Power DSM Table

EXHIBIT SHEIKH-DIRECT-3

Nevada Power Company
d/b/a NV Energy
2023 Demand Side Management Monthly Costs by Program
January 01, 2023 through December 31, 2023

	(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
Line No.	**Program Title**	**Project Nos.**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**	**Total**	**Line No.**
1	Energy Ed Residential - NPC	ECS0900Y23	$ 6,889	$ (5,733)	$ 17,701	$ 7,966	$ 11,613	$ 10,723	$ 20,693	$ 5,151	$ 7,123	$ 13,796	$ 127,286	$ 59,233	**$ 282,440.98**	1
2	Energy Ed Residential - NPC	ECS0900Y22										$ (1,245)			**$ (1,244.59)**	2
3	Energy Ed Commercial - NPC	ECS0901Y23	$ 9,984	$ 8,547	$ 8,636	$ 1,821	$ 13,548	$ 8,833	$ 9,667	$ 1,790	$ 8,439	$ 8,908	$ 9,126	$ 22,810	**$ 112,109.47**	3
4	Energy Ed Commercial - NPC	ECS0901Y22										$ (751)			**$ (750.96)**	4
5	Program Development - NPC	ECS0908Y23	$ 9,290	$ 41,627	$ 16,410	$ 75,058	$ 21,388	$ (833)	$ 55,067	$ 60,766	$ 88,128	$ 128,934	$ 214,663	$ 17,293	**$ 727,789.93**	5
6	Program Development - NPC	ECS0908Y22										$ (889)			**$ (888.99)**	6
7	Residential DR Build - NPC	ECS0909Y23	$ 304,584	$ 317,795	$ 822,063	$ 698,948	$ 585,899	$ 353,858	$ 787,987	$ 855,189	$ 418,271	$ 280,282	$ 674,356	$ 1,073,866	**$ 7,173,098.62**	7
8	Residential DR Build - NPC	ECS0909Y22	$ 134,755	$ 25								$ (34,858)			**$ 99,921.96**	8
9	Residential AC Program - NPC	ECS0910Y23	$ 52,297	$ 143,242	$ 56,421	$ 24,909	$ 236,633	$ 8,695	$ 298,269	$ 522,488	$ 455,867	$ 825,267	$ 450,142	$ 877,944	**$ 3,952,175.35**	9
10	Residential AC Program - NPC	ECS0910Y22										$ (18,763)			**$ (18,762.58)**	10
11	Residential Equipment & Plug Loads - NPC	ECS0912Y23	$ 118,865	$ 195,664	$ 45,943	$ 63,882	$ 367,315	$ 95,968	$ 211,908	$ 271,822	$ 408,733	$ 1,072,820	$ 1,186,051	$ 151,724	**$ 4,190,696.02**	11
12	Residential Equipment & Plug Loads - NPC	ECS0912Y22										$ (6,260)			**$ (6,260.45)**	12
13	Business Program - NPC	ECS0913Y23	$ 309,315	$ 355,893	$ 478,731	$ 1,047,185	$ 396,383	$ 641,457	$ 500,359	$ 839,288	$ 533,911	$ 1,032,082	$ 722,236	$ 5,991,638	**$ 12,848,478.05**	13
14	Business Program - NPC	ECS0913Y22	$ 1,171,453									$ (62,548)	$ 912	$ (912)	**$ 1,108,904.99**	14
15	Business Program - NPC Accounting adjustment	ECS0913Y23												$ (1,130,100)	**$ (1,130,099.50)**	15
16	Schools Program - NPC	ECS0915Y23	$ (34,392)	$ 70,125	$ 693,500	$ (41,095)	$ 34,727	$ 139,651	$ 31,870	$ 75,459	$ 45,902	$ 21,028	$ 34,078	$ 927,900	**$ 1,998,754.92**	16
17	Schools Program - NPC	ECS0915Y22			$ (587,407)							$ (6,024)			**$ (593,431.25)**	17
18	Residential DR Manage - NPC	ECS0918Y23	$ 100,213	$ 448,567	$ 417,821	$ 328,337	$ 374,709	$ 661,179	$ 505,058	$ 631,695	$ 659,092	$ 367,928	$ 396,108	$ 517,790	**$ 5,408,496.69**	18
19	Residential DR Manage - NPC	ECS0918Y22	$ (56)	$ (175,839)								$ (31,719)			**$ (207,613.91)**	19
20	Residential Codes & New Construction - NPC	ECS0957Y23	$ 12,676	$ 65,631	$ 141,493	$ 13,357	$ 494,205	$ 65,110	$ (18,138)	$ 234,286	$ 255,125	$ 354,720	$ 271,380	$ 837,841	**$ 2,727,686.42**	20
21	Residential Codes & New Construction - NPC	ECS0957Y22										$ (1,876)			**$ (1,876.26)**	21
22	Low Income - NPC	ECS0962Y23	$ 156,987	$ 438,837	$ (88,123)	$ 148,044	$ 189,002	$ 159,447	$ 198,045	$ 192,325	$ 142,780	$ 272,791	$ 102,194	$ 156,726	**$ 2,069,054.68**	22
23	Low Income - NPC	ECS0962Y22										$ (9,915)			**$ (9,914.69)**	23
24	Commercial DR Manage - NPC	ECS2878Y23	$ (48,700)	$ 3,725	$ 17,217	$ 40,420	$ 38,221	$ 38,163	$ 46,024	$ 38,524	$ 32,009	$ 38,718	$ 42,224	$ 28,222	**$ 314,766.38**	24
25	Commercial DR Manage - NPC	ECS2878Y22										$ (3,575)			**$ (3,574.72)**	25
26	Commercial DR Build - NPC	ECS2880Y23	$ 68,083	$ (38,037)	$ 25,631	$ 27,876	$ 26,916	$ 23,043	$ 60,456	$ 71,379	$ 60,187	$ 32,686	$ 16,118	$ 28,651	**$ 402,988.52**	26
27	Commercial DR Build - NPC	ECS2868Y19		$ 61,853	$ (217)										**$ 61,636.16**	27
28	Commercial DR Build - NPC	ECS2880Y22										$ (3,318)			**$ (3,318.23)**	28
29	Online Energy Assessments - NPC	ECS8110Y23	$ 42,571	$ 39,754	$ 39,687	$ 38,874	$ 72,355	$ 8,263	$ 43,923	$ 39,078	$ 40,424	$ 41,390	$ 49,928	$ 49,252	**$ 505,499.62**	29
30	Online Energy Assessments - NPC	ECS8110Y22										$ (4,700)			**$ (4,700.02)**	30
31	Home Energy Reports - NPC	ECS8111Y23	$ 89,367	$ 20,902	$ 23,169	$ (20,899)	$ 288,897	$ 75,058	$ 69,671	$ 70,759	$ 67,214	$ 102,238	$ 136,202	$ 33,375	**$ 955,953.78**	31
32	Home Energy Reports - NPC	ECS8111Y22										$ (3,239)			**$ (3,239.00)**	32
33	In-Home Energy Assessments - NPC	ECS8113Y23	$ 232,809	$ (25,099)	$ 143,384	$ 128,899	$ 151,282	$ 114,157	$ 151,661	$ 140,247	$ 124,632	$ 131,478	$ 52,881	$ 40,831	**$ 1,387,161.44**	33
34	In-Home Energy Assessments - NPC	ECS8113Y22										$ (4,780)			**$ (4,779.55)**	34
35	Direct Install/Deep Retrofits - NPC	ECS8114Y23	$ 429	$ 32,363	$ 38,492	$ 71,914	$ 91,638	$ 62,073	$ 62,041	$ 34,715	$ 64,815	$ 41,023	$ 49,732	$ 127,168	**$ 676,404.30**	35
36	Direct Install/Deep Retrofits - NPC	ECS8114Y22										$ (3,041)			**$ (3,041.32)**	36
37	Online Marketplace	DSMONLMKPL							$ 101,500	$ 28,000		$ 147,041	$ (40,680)	$ 30,652	**$ 266,513.28**	37
38	IRP Planning South	ECS0963Y23			$ 10,000	$ 19,063		$ 17,056	$ 26,355	$ 401,499	$ 90,719	$ 36,116	$ 8,180	$ (415,786)	**$ 193,200.62**	38
39	Labor Accrual	GENERIC	$ (22,998)	$ (8,288)	$ 42,685	$ 1,484	$ 29,618	$ 34,313	$ 16,838	$ (99,353)	$ 14,956	$ 51,397	$ (22,096)	$ (30,568)	**$ 7,987.61**	39
40	**Total**		**$ 2,714,421.65**	**$ 1,991,555.88**	**$ 2,363,237.51**	**$ 2,676,041.43**	**$ 3,424,348.54**	**$ 2,516,214.96**	**$ 3,179,253.47**	**$ 4,415,106.78**	**$ 3,518,325.84**	**$ 4,803,142.38**	**$ 4,481,024.66**	**$ 9,395,550.67**	**$ 45,478,223.77**	40

EXHIBIT SHEIKH-DIRECT-4

Nevada Power Company
d/b/a NV Energy
2023 Summary of the Budgets, Costs and Carrying Charges

	(a)	(b)	(c)	(d)	
Ln No	**Programs**	**Budget [1]**	**Costs [2]**	**Carrying Charges**	**Ln No**
1	Energy Education	$ 450,000	$ 392,554.90		1
2	Residential Energy Reports	$ 898,040	$ 952,714.78		2
3	Energy Assessments	$ 1,946,960	$ 1,883,181.49		3
4	Program Development	$ 700,000	$ 726,900.94		4
5	Residential Equipment & Plug Loads	$ 6,100,000	$ 8,117,848.34		5
6	Residential Codes & New Construction	$ 1,300,000	$ 2,725,810.16		6
7	Residential Direct Install	$ 740,000	$ 673,362.98		7
8	Residential Low Income QAR	$ 3,375,000	$ 2,059,139.99		8
9	Residential Demand Response - Manage	$ 7,800,000	$ 5,200,882.78		9
10	Residential Demand Response - Build	$ 7,797,800	$ 7,273,020.58		10
11	Commercial Demand Response - Manage	$ 900,000	$ 311,191.66		11
12	Commercial Demand Response - Build	$ 743,701	$ 461,306.45		12
13	Business Program	$ 14,000,000	$ 13,957,383.04		13
14	Business Program - Accounting adjustment [3]	$ -	$ (1,130,099.50)		14
15	Energy Smart Schools	$ 1,350,000	$ 1,405,323.67		15
16	Online Marketplace [4]	$ -	$ 266,513.28		16
17	IRP Planning South [5]	$ -	$ 193,200.62		17
18	**Subtotal**	**$ 48,101,501**	**$ 45,470,236.16**	**$ -**	18
19	Generic - Payroll Accrual		$ 7,987.61		19
20	Carrying Charge			$ (52,855.43)	20
21	**Total**	**$ 48,101,501**	**$ 45,478,223.77**	**$ (52,855.43)**	21

[1] Docket No. 22-07004, November 14, 2022, Order at Attachment 1, Nevada Power DSM Table
[2] The total program costs do not reflect DSM recapture amounts from the 704B applications in Docket Nos. 16-11034 or 18-12019. The resulting reductions to the approved DSM program budgets shown in this exhibit are included in the Base EEPR rate calcuation shown for all classes in Exhibit J.
[3] There was an accounting adjustment needed to be made for -$1,130,099.50 due to an accrual error. This amount has to do with the incentives which were approved in December of 2022 but were not accrued.
[4] The total internal allocated budget to Online Marketplace program was $260,000 out of the Education, Outreach and Marketing budget from each program.

[5] This represents the cost of the Net-To-Gross ("NTG") study that investigated free ridership and spillover effects for all the programs. This NTG study is a requirement of the company's DSM three-year action plan that is filed with the upcoming 2024 integrated resources plan.

EXHIBIT SHEIKH-DIRECT-5

Nevada Power Company
d/b/a NV Energy
2023 Summary of DSM Program Costs by Category

	(a)	(b)=(c)+(g)+(h)+(i)+(j)+(k)+(l)	(c)=(d)+(e)+(f)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
			Utility Administration Costs										
Ln No	Program Title	Actual Expenditures	Total	Labor	Overhead	Other	M&V Contractor Costs	Implementation Payments	Incentives to Others	Direct Rebates to Ratepayers	Software	Education, Outreach, Training & Marketing	Ln No
1	Business Program	$ 13,957,383	$ 1,055,058	$ 609,216	$ 428,277	$ 17,564	$ 218,535	$ 5,794,371		$ 6,469,766		$ 419,653	1
2	Business Program - NPC Accounting adjustment	$ (1,130,100)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,130,100)	$ -	$ -	2
3	Schools	$ 1,405,324	$ 100,825	$ 58,769	$ 41,314	$ 741	$ 21,073	$ 1,150,126	$ 94,230			$ 39,070	3
4	**SubTotal Commercial**	**$ 14,232,607**	**$ 1,155,882**	**$ 667,986**	**$ 469,592**	**$ 18,305**	**$ 239,608**	**$ 6,944,497**	**$ 94,230**	**$ 5,339,667**	**$ -**	**$ 458,723**	4
5	Energy Assessments	$ 1,883,181	$ 174,427	$ 84,860	$ 59,657	$ 29,910	$ 31,404	$ 970,855	$ -	$ -	$ 650,960	$ 55,536	5
6	Program Development	$ 726,901	$ 51,649	$ 30,147	$ 21,193	$ 310		$ 669,218				$ 6,034	6
7	Energy Education	$ 392,555	$ 40,301	$ 19,386	$ 13,629	$ 7,286	$ 7,024	$ 282,664	$ -	$ -	$ -	$ 62,566	7
8	Online Marketplace	$ 266,513	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 266,513	8
9	IRP Planning South	$ 193,201	$ -	$ -	$ -	$ -	$ -	$ 193,201	$ -	$ -	$ -	$ -	9
10	**SubTotal Other**	**$ 3,462,351**	**$ 266,378**	**$ 134,392**	**$ 94,479**	**$ 37,506**	**$ 38,428**	**$ 2,115,937**	**$ -**	**$ -**	**$ 650,960**	**$ 390,649**	10
11	Residential Air Conditioning	$ 3,933,413	$ 333,339	$ 193,356	$ 135,813	$ 4,171	$ 64,458	$ 696,897	$ 2,833,183	$ 125		$ 5,411	11
12	Residential Direct Install	$ 673,363	$ 64,146	$ 32,118	$ 22,578	$ 9,450	$ 11,200	$ 575,132	$ 1,163			$ 21,723	12
13	Residential Energy Reports	$ 952,715	$ 67,737	$ 39,025	$ 27,435	$ 1,277	$ 13,006	$ 4,264			$ 840,885	$ 26,822	13
14	Residential Equipment & Plug Loads	$ 4,184,436	$ 128,480	$ 71,851	$ 50,629	$ 6,001	$ 27,837	$ 1,276,607	$ 2,486,075		$ 42,000	$ 223,436	14
15	Residential Low Income	$ 2,059,140	$ 250,624	$ 145,254	$ 102,163	$ 3,207	$ 45,927	$ 1,137,171	$ 522,678			$ 102,740	15
16	Residential Codes & New Construction	$ 2,725,810	$ 97,325	$ 56,562	$ 39,709	$ 1,053	$ 15,145	$ 1,735,656	$ 836,160			$ 41,524	16
17	**SubTotal Residential**	**$ 14,528,876**	**$ 941,651**	**$ 538,165**	**$ 378,327**	**$ 25,159**	**$ 177,573**	**$ 5,425,728**	**$ 6,679,259**	**$ 125**	**$ 882,885**	**$ 421,656**	17
18	Residential Demand Response - Build	$ 7,273,021	$ 627,745	$ 344,497	$ 241,933	$ 41,316	$ 121,721	$ 5,362,685		$ 904,159	$ 23,001	$ 233,710	18
19	Residential Demand Response - Manage	$ 5,200,883	$ 621,016	$ 338,865	$ 238,219	$ 43,932	$ 117,661	$ 2,872,620		$ 667,075	$ 693,788	$ 228,724	19
20	Commercial Demand Response - Build	$ 461,306	$ 56,709	$ 32,463	$ 22,821	$ 1,425	$ 11,609	$ 309,890		$ 61,636		$ 21,462	20
21	Commercial Demand Response - Manage	$ 311,192	$ 67,781	$ 39,100	$ 27,487	$ 1,194	$ 13,464	$ 197,946	$ 1,094		$ 4,652	$ 26,256	21
22	**SubTotal Demand Response**	**$ 13,246,401**	**$ 1,373,252**	**$ 754,925**	**$ 530,461**	**$ 87,866**	**$ 264,455**	**$ 8,743,139**	**$ 1,094**	**$ 1,632,870**	**$ 721,440**	**$ 510,152**	22
23	Payroll Accrual	$ 7,988	$ 7,988	$ 7,988									23
24	**Total all categories**	**$ 45,478,224**	**$ 3,745,150**	**$ 2,103,455**	**$ 1,472,859**	**$ 168,836**	**$ 720,064**	**$ 23,229,302**	**$ 6,774,583**	**$ 6,972,661**	**$ 2,255,285**	**$ 1,781,179**	24

EXHIBIT SHEIKH-DIRECT-6

Nevada Power Company
d/b/a NV Energy
2023 All Clean Energy Programs
GL Accounts: GL Accounts: 182353, 182303, 182331, 182332
January 01, 2023 through December 31, 2023

Ln No	Category	Budget ($)	Actual ($)	Variances ($) Under/(Over)	Ln No
1	Beginning Balance		**3,366,670**		1
2					2
3	Contractor Costs	416,110	373,330	42,780	3
4	Marketing Cost [1]	112,350	(39,704)	152,054	4
5	Education and Training Costs	5,706	-	5,706	5
6	Utility Administration Costs	351,051	302,970	48,080	6
7	**Total CE Program Costs**	**885,216**	**636,595**	**248,621**	7
8					8
9	Total Incentive Payments	4,761,001	4,190,373	570,628	9
10					10
11	**Total CE Program Expenditures**	**5,646,217**	**4,826,968**	**819,248**	11
12					12
13	CE Program Revenue		(14,814,066)		13
14	Carry Charges		(183,770)		14
15	Application Fees		(46,114)		15
16	**Ending Balance**		**(6,850,312)**		16
17	[1] The credit of $39,704 includes the credit of $49,750 for a market survey incorrectly charged to the EVID program. This charge was reclassified to the Transportation Electrification study account in January 2023.				17

EXHIBIT SHEIKH-DIRECT-7

Nevada Power Company
d/b/a NV Energy
2023 Solar and Lower Income Solar Energy Programs (LISEP)
GL Accounts: 182353
January 01, 2023 through December 31, 2023

Ln No	Category	Budget ($)	Actual ($)	Variances ($) Under / (Over)	Ln No
1	Beginning Balance		**5,229,590**		1
2					2
3	Contractor Costs	76,203	77,760	(1,558)	3
4	Marketing Cost	-	-	-	4
5	Education and Training Costs	-	-	-	5
6	Utility Administration Costs	39,655	45,265	(5,610)	6
7	**Total Solar/LISEP Program Costs**	**115,858**	**123,025**	**(7,167)**	7
8					8
9	Total Incentive Payments	941,069	406,512	534,557	9
10					10
11	**Total Solar/LISEP Program Expenditures**	**1,056,926**	**529,537**	**527,389**	11
12					12
13	Program Revenue		(12,669,626)		13
14	Carry Charges		(138,490)		14
15	Application Fees		(2,084)		15
16	**Ending Balance**		**(7,051,073)**		16

EXHIBIT SHEIKH-DIRECT-7A

Nevada Power Company
d/b/a NV Energy
2023 Solar and Lower Income Solar Energy Programs (LISEP)
Program Activity through December 31, 2023

Line No.	(a)	(b) Dec-22	(c) January	(d) February	(e) March	(f) April	(g) May	(h) June	(i) July	(j) August	(k) September	(l) October	(m) November	(n) December	(o) Summary of Annual Activity	Line No.
1	Account No. 182.353															1
2	Beginning Balance	$ 5,889,506	$ 5,229,590	$ 4,277,400	$ 3,450,964	$ 2,557,640	$ 1,628,818	$ 438,425	$ (967,753)	$ (2,994,944)	$ (4,777,732)	$ (6,164,721)	$ (6,754,816)	$ (7,056,253)		2
3	Deferred Costs	$ 338,161	$ 15,003	$ 41,127	$ 15,042	$ 15,149	$ 36,744	$ 14,011	$ 4,650	$ 6,376	$ 4,642	$ (110,560)	$ 77,925	$ 407,344		3
4	Prospective Rate (Part A)	$ (121,050)	$ (116,780)	$ (104,503)	$ (108,677)	$ (112,195)	$ (144,696)	$ (166,419)	$ (236,965)	$ (207,164)	$ (159,435)	$ (37,871)	$ (26,227)	$ (28,639)		4
5	Amortization Rate (Part B)	$ (907,959)	$ (875,712)	$ (783,472)	$ (814,817)	$ (841,411)	$ (1,085,034)	$ (1,248,046)	$ (1,777,161)	$ (1,553,741)	$ (1,195,732)	$ (401,711)	$ (311,397)	$ (331,820)		5
6	Adjustments															6
7	Subtotal	$ 5,198,658	$ 4,252,100	$ 3,430,553	$ 2,542,512	$ 1,619,183	$ 435,831	$ (962,029)	$ (2,977,229)	$ (4,749,473)	$ (6,128,257)	$ (6,714,863)	$ (7,014,516)	$ (7,009,368)		7
8																8
9	Carrying Charges	$ 30,932	$ 25,300	$ 20,412	$ 15,128	$ 9,634	$ 2,593	$ (5,724)	$ (17,715)	$ (28,259)	$ (36,463)	$ (39,953)	$ (41,736)	$ (41,706)		9
10																10
11	Ending Balance	$ 5,229,590	$ 4,277,400	$ 3,450,964	$ 2,557,640	$ 1,628,818	$ 438,425	$ (967,753)	$ (2,994,944)	$ (4,777,732)	$ (6,164,721)	$ (6,754,816)	$ (7,056,253)	$ (7,051,073)		11
12																12
13																13
14	**Cumulative Balance**	$ 5,889,506	$ 5,229,590	$ 4,277,400	$ 3,450,964	$ 2,557,640	$ 1,628,818	$ 438,425	$ (967,753)	$ (2,994,944)	$ (4,777,732)	$ (6,164,721)	$ (6,754,816)	$ (7,056,253)	$ 5,229,590	14
15	Deferrals	$ 338,161	$ 15,003	$ 41,127	$ 15,042	$ 15,149	$ 36,744	$ 14,011	$ 4,650	$ 6,376	$ 4,642	$ (110,560)	$ 77,925	$ 407,344	$ 527,453	15
16	Prospective Rate (Part A)	$ (121,050)	$ (116,780)	$ (104,503)	$ (108,677)	$ (112,195)	$ (144,696)	$ (166,419)	$ (236,965)	$ (207,164)	$ (159,435)	$ (37,871)	$ (26,227)	$ (28,639)	$ (1,449,572)	16
17	Amortization Rate (Part B)	$ (907,959)	$ (875,712)	$ (783,472)	$ (814,817)	$ (841,411)	$ (1,085,034)	$ (1,248,046)	$ (1,777,161)	$ (1,553,741)	$ (1,195,732)	$ (401,711)	$ (311,397)	$ (331,820)	$ (11,220,054)	17
18	Adjustments	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	18
19	Carrying Charges	$ 30,932	$ 25,300	$ 20,412	$ 15,128	$ 9,634	$ 2,593	$ (5,724)	$ (17,715)	$ (28,259)	$ (36,463)	$ (39,953)	$ (41,736)	$ (41,706)	$ (138,490)	19
20	**Cumulative Balance**	$ 5,229,590	$ 4,277,400	$ 3,450,964	$ 2,557,640	$ 1,628,818	$ 438,425	$ (967,753)	$ (2,994,944)	$ (4,777,732)	$ (6,164,721)	$ (6,754,816)	$ (7,056,253)	$ (7,051,073)	$ (7,051,073)	20
21																21
22																22
23	Carrying Charge Rates															23
24																24
25	Docket 17-06003	7.14%	0.595%													25

EXHIBIT SHEIKH-DIRECT-8

Nevada Power Company
d/b/a NV Energy
2023 Electric Vehicle Infrastructure Demonstration (EVID) Program
GL Accounts: 182303
January 01, 2023 through December 31, 2023

Ln No	Category	Budget ($)	Actual ($)	Variances ($) Under/(Over)	Ln No
1	Beginning Balance		**$ (763,459)**		1
2					2
3	Contractor Costs	$ 200,391	$ 144,169	$ 56,221	3
4	Marketing Cost [1]	$ 111,850	$ (39,867)	$ 151,717	4
5	Education and Training Costs	$ 5,025		$ 5,025	5
6	Utility Administration Costs	$ 174,597	$ 124,365	$ 50,231	6
7	**Total EVID Program Costs**	**$ 491,862**	**$ 228,667**	**$ 263,195**	7
8					8
9	Total Incentive Payments	$ 2,702,956	$ 2,813,548	$ (110,592)	9
10					10
11	**Total EVID Program Expenditures**	**$ 3,194,818**	**$ 3,042,215**	**$ 152,603**	11
12					12
13	Program Revenue		$ (485,685)		13
14	Carry Charges		$ 53,711		14
15	Application Fees		$ -		15
16	**Ending Balance**		**$ 1,846,782**		16
17					17

18 [1] The credit of $39,867 contains: the $49,750 credit that adjusted the EV market survey that was charged to this program in error, and additional Marketing Costs of $9,882 spent during the program year. Please refer to Docket 23-03005, Direct Testimony of Ali Sheikh. 18

EXHIBIT SHEIKH-DIRECT-8A

Nevada Power Company
d/b/a NV Energy
2023 Electric Vehicle Infrastructure Demonstration (EVID) Program
Program Activity through December 31, 2023

Line No.	(a)	(b) Dec-22	(c) January	(d) February	(e) March	(f) April	(g) May	(h) June	(i) July	(j) August	(k) September	(l) October	(m) November	(n) December	(o) Summary of Annual Activity	Line No.
1	Account No. 182.303															1
2	Beginning Balance	$ (1,019,245)	$ (763,459)	$ (583,489)	$ (229,202)	$ 351,652	$ 647,690	$ 745,261	$ 799,829	$ 1,042,402	$ 1,084,758	$ 1,118,585	$ 1,213,953	$ 1,042,509		2
3	Deferred Costs	245,190	168,846	342,552	565,194	278,180	75,078	29,037	206,785	10,047	7,278	308,120	38,178	1,012,920		3
4	Prospective Rate (Part A)	(166,367)	(160,526)	(143,794)	(149,422)	(154,280)	(198,932)	(228,812)	(325,829)	(284,842)	(219,235)	(276,726)	(255,119)	(262,528)		4
5	Amortization Rate (Part B)	181,479	175,102	156,884	163,003	168,307	217,017	249,612	355,450	310,734	239,168	56,794	39,331	42,958		5
6	Adjustments															6
7	Subtotal	(758,943)	(580,038)	(227,847)	349,572	643,859	740,853	795,098	1,036,236	1,078,342	1,111,969	1,206,772	1,036,342	1,835,859	-	7
8																8
9	Carrying Charges	(4,516)	(3,451)	(1,356)	2,080	3,831	4,408	4,731	6,166	6,416	6,616	7,180	6,166	10,923		9
10																10
11	Ending Balance	$ (763,459)	$ (583,489)	$ (229,202)	$ 351,652	$ 647,690	$ 745,261	$ 799,829	$ 1,042,402	$ 1,084,758	$ 1,118,585	$ 1,213,953	$ 1,042,509	$ 1,846,782	$ -	11
12																12
13																13
14	**Cumulative Balance**	$ (1,019,245)	$ (763,459)	$ (583,489)	$ (229,202)	$ 351,652	$ 647,690	$ 745,261	$ 799,829	$ 1,042,402	$ 1,084,758	$ 1,118,585	$ 1,213,953	$ 1,042,509	$ (763,459)	14
15	Deferrals	245,190	168,846	342,552	565,194	278,180	75,078	29,037	206,785	10,047	7,278	308,120	38,178	1,012,920	3,042,215	15
16	Prospective Rate (Part A)	(166,367)	(160,526)	(143,794)	(149,422)	(154,280)	(198,932)	(228,812)	(325,829)	(284,842)	(219,235)	(276,726)	(255,119)	(262,528)	(2,660,044)	16
17	Amortization Rate (Part B)	181,479	175,102	156,884	163,003	168,307	217,017	249,612	355,450	310,734	239,168	56,794	39,331	42,958	2,174,359	17
18	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18
19	Carrying Charges	(4,516)	(3,451)	(1,356)	2,080	3,831	4,408	4,731	6,166	6,416	6,616	7,180	6,166	10,923	53,711	19
20	**Cumulative Balance**	(763,459)	(583,489)	(229,202)	351,652	647,690	745,261	799,829	1,042,402	1,084,758	1,118,585	1,213,953	1,042,509	1,846,782	1,846,782	20
21																21
22																22
23	Carrying Charge Rates															23
24	Docket 17-06003	7.140%	0.595%													24

EXHIBIT SHEIKH-DIRECT-9

Exhibit Sheikh-Direct-9

Sheikh

Nevada Power Company
d/b/a NV Energy
2023 Small Energy Storage Program (SESP)
GL Accounts: 182331
January 01, 2023 through December 31, 2023

Ln No	Category	Budget ($)	Actual ($)	Variances ($) Under/(Over)	Ln No
1	Beginning Balance		**(298,226)**		1
2					2
3	Contractor Costs	125,134	95,054	30,080	3
4	Marketing Cost	200	152	48	4
5	Education and Training Costs	681		681	5
6	Utility Admininstration Costs	85,089	85,664	(575)	6
7	**Total SESP Program Costs**	**211,103**	**180,870**	**30,233**	7
8					8
9	Total Incentive Payments	866,976	970,312	(103,336)	9
10					10
11	**Total SESP Program Expenditures**	**1,078,079**	**1,151,183**	**(73,104)**	11
12					12
13	Program Revenue		(1,322,893)		13
14	Carry Charges		(23,816)		14
15	Application Fees		(43,530)		15
16	**Ending Balance**		**(537,282)**		16

EXHIBIT SHEIKH-DIRECT-9A

Nevada Power Company
d/b/a NV Energy
2023 Small Energy Storage Program (SESP)
Program Activity through December 31, 2023

Line No.	(a)	(b) Dec-22	(c) January	(d) February	(e) March	(f) April	(g) May	(h) June	(i) July	(j) August	(k) September	(l) October	(m) November	(n) December	(o) Summary of Annual Activity	Line No.
1	Account No. 182.331															1
2	Beginning Balance	$ (318,637)	$ (298,226)	$ (328,445)	$ (162,563)	$ (109,839)	$ (51,361)	$ (91,927)	$ (195,325)	$ (362,045)	$ (520,911)	$ (606,832)	$ (536,980)	$ (522,926)		2
3	Deferred Costs	128,105	73,898	258,252	148,437	156,949	86,565	43,005	43,115	25,484	57,171	124,569	58,037	32,170		3
4	Prospective Rate (Part A)	(90,794)	(87,579)	(78,358)	(81,485)	(84,143)	(108,504)	(124,804)	(177,718)	(155,374)	(119,575)	(65,222)	(55,576)	(58,060)		4
5	Amortization Rate (Part B)	(15,136)	(14,596)	(13,051)	(13,579)	(14,023)	(18,084)	(20,444)	(29,975)	(25,896)	(19,928)	13,682	14,686	14,712		5
6	Adjustments															6
7	Subtotal	(296,462)	(326,502)	(161,601)	(109,190)	(51,057)	(91,383)	(194,170)	(359,903)	(517,830)	(603,242)	(533,804)	(519,833)	(534,104)		7
8																8
9	Carrying Charges	(1,764)	(1,943)	(962)	(650)	(304)	(544)	(1,155)	(2,141)	(3,081)	(3,589)	(3,176)	(3,093)	(3,178)		9
10																10
11	Ending Balance	$ (298,226)	$ (328,445)	$ (162,563)	$ (109,839)	$ (51,361)	$ (91,927)	$ (195,325)	$ (362,045)	$ (520,911)	$ (606,832)	$ (536,980)	$ (522,926)	$ (537,282)		11
12																12
13																13
14	**Cumulative Balance**	$ (318,637)	$ (298,226)	$ (328,445)	$ (162,563)	$ (109,839)	$ (51,361)	$ (91,927)	$ (195,325)	$ (362,045)	$ (520,911)	$ (606,832)	$ (536,980)	$ (522,926)	$ (298,226)	14
15	Deferrals	128,105	73,898	258,252	148,437	156,949	86,565	43,005	43,115	25,484	57,171	124,569	58,037	32,170	1,107,653	15
16	Prospective Rate (Part A)	(90,794)	(87,579)	(78,358)	(81,485)	(84,143)	(108,504)	(124,804)	(177,718)	(155,374)	(119,575)	(65,222)	(55,576)	(58,060)	(1,196,399)	16
17	Amortization Rate (Part B)	(15,136)	(14,596)	(13,051)	(13,579)	(14,023)	(18,084)	(20,444)	(29,975)	(25,896)	(19,928)	13,682	14,686	14,712	(126,494)	17
18	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18
19	Carrying Charges	(1,764)	(1,943)	(962)	(650)	(304)	(544)	(1,155)	(2,141)	(3,081)	(3,589)	(3,176)	(3,093)	(3,178)	(23,816)	19
	Rounding															
20	**Cumulative Balance**	(298,226)	(328,445)	(162,563)	(109,839)	(51,361)	(91,927)	(195,325)	(362,045)	(520,911)	(606,832)	(536,980)	(522,926)	(537,282)	(537,282)	20
21																21
22																22
23	Carrying Charge Rates															23
24	Docket 17-06003	7.14%	0.595%													24

EXHIBIT SHEIKH-DIRECT-10

Nevada Power Company
d/b/a NV Energy
2023 Large Energy Storage Program (LESP)
GL Accounts: 182332
January 01, 2023 through December 31, 2023

Ln No	Category	Budget ($)	Actual ($)	Variances ($) Under/(Over)	Ln No
1	Beginning Balance		**(801,236)**		1
2					2
3	Contractor Costs	14,384	56,347	(41,963)	3
4	Marketing Cost	300	11	289	4
5	Education and Training Costs	-		-	5
6	Utility Admininstration Costs	51,710	47,676	4,034	6
7	**Total LESP Program Costs**	**66,394**	**104,034**	**(37,640)**	7
8					8
9	Total Incentive Payments	250,000	-	250,000	9
10					10
11	**Total LESP Program Expenditures**	**316,394**	**104,034**	**212,360**	11
12					12
13	Program Revenue		(335,862)		13
14	Carry Charges		(75,175)		14
15	Application Fees		(500)		15
16	**Ending Balance**		**(1,108,739)**		16

EXHIBIT SHEIKH-DIRECT-10A

Nevada Power Company
d/b/a NV Energy
2023 Large Energy Storage Program (LESP)
Program Activity through December 31, 2023

Line No.	(a)	(b) Dec-22	(c) January	(d) February	(e) March	(f) April	(g) May	(h) June	(i) July	(j) August	(k) September	(l) October	(m) November	(n) December	(o) Summary of Annual Activity	Line No.
1	Account No. 182.332															1
2	Beginning Balance	$ (756,621)	$(801,236)	$ (844,825)	$ (870,093)	$ (909,111)	$ (949,994)	$ (988,768)	#########	#########	#########	#########	#########	#########		2
3	Deferred Costs	5,505	5,189	19,083	7,106	6,810	21,328	18,777	2,163	10,005	(1,041)	5,890	4,036	4,187		3
4	Prospective Rate (Part A)	(45,405)	(43,794)	(39,166)	(40,739)	(42,070)	(54,251)	(62,402)	(88,857)	(77,688)	(59,786)	(3,150)	942	235		4
5	Amortization Rate (Part B)	25	12	(39)	(8)	(5)	(2)	(1)	(4)	3	(4)	58,921	57,458	58,531		5
6	Adjustments															6
7	Subtotal	(796,497)	(839,828)	(864,946)	(903,734)	(944,375)	(982,920)	(1,032,393)	(1,125,234)	(1,199,608)	(1,267,577)	(1,213,458)	(1,158,243)	(1,102,181)		7
8																8
9	Labor overhead adjustment															9
10	Carrying Charges	(4,739)	(4,997)	(5,146)	(5,377)	(5,619)	(5,848)	(6,143)	(6,695)	(7,138)	(7,542)	(7,220)	(6,892)	(6,558)		10
11																11
12	Ending Balance	$ (801,236)	$(844,825)	$ (870,093)	$ (909,111)	$ (949,994)	$ (988,768)	#########	#########	#########	#########	#########	#########	#########		12
13																13
14																14
15	**Cumulative Balance**	$ (756,621)	$(801,236)	$ (844,825)	$ (870,093)	$ (909,111)	$ (949,994)	$ (988,768)	#########	#########	#########	#########	#########	#########	$ (801,236)	15
16	Deferrals	5,505	5,189	19,083	7,106	6,810	21,328	18,777	2,163	10,005	(1,041)	5,890	4,036	4,187	103,534	16
17	Prospective Rate (Part A)	(45,405)	(43,794)	(39,166)	(40,739)	(42,070)	(54,251)	(62,402)	(88,857)	(77,688)	(59,786)	(3,150)	942	235	(510,724)	17
18	Amortization Rate (Part B)	25	12	(39)	(8)	(5)	(2)	(1)	(4)	3	(4)	58,921	57,458	58,531	174,863	18
19	Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
20	Carrying Charges	(4,739)	(4,997)	(5,146)	(5,377)	(5,619)	(5,848)	(6,143)	(6,695)	(7,138)	(7,542)	(7,220)	(6,892)	(6,558)	(75,175)	20
21	**Cumulative Balance**	(801,236)	(844,825)	(870,093)	(909,111)	(949,994)	(988,768)	(1,038,536)	(1,131,929)	(1,206,746)	(1,275,119)	(1,220,678)	(1,165,134)	(1,108,739)	(1,108,739)	21
22																22
23																23
24	Carrying Charge Rates															24
25	Docket 17-06003	7.14%	0.595%													25

AFFIRMATION

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

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

Date: March 1, 2024

A. N.

ALI SHEIKH

KURT G. STRUNK

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Kurt G. Strunk

I. QUALIFICATIONS

1. Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Kurt G. Strunk. I am a Senior Managing Director of National Economic Research Associates ("NERA"). My business address is 1166 Avenue of the Americas, New York, New York, 10036. I am filing testimony on behalf of Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company").

2. Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I have 30 years of experience consulting to governments, regulators, and utilities on energy-related matters. My practice at NERA focuses on the strategic, regulatory, and financial issues facing electric and gas utilities as the markets in which they operate, restructure and evolve. My work often involves the analysis of utility procurement decisions and procurement implementation. I have advised on the structuring and origination of a number of wholesale energy transactions and the acquisition of fuels by regulated utilities. I have served as an expert in cases dealing with the application of the prudence standard to utility decision making.

Many of my assignments have required that I perform in-depth analyses of power and gas markets in Nevada and the western United States. In numerous cases, I have presented those analyses in testimony before regulators. As a result, I am very familiar with the market and regulatory and legislative environment in which the Company operates.

I have been retained as a testifying expert in matters before state and provincial public utility boards in the United States and Canada, the Federal Energy Regulatory Commission, U.S. Tax Court, U.S. Federal Court, U.S. Bankruptcy Court, Arbitrators, and the National Energy Board in Canada. I have submitted pre-filed expert testimony in prior Deferred Energy proceedings for Nevada Power Company and Sierra (Docket Nos. 12-03004, 12-03005, 12-03006, 13-03003, 13-03004, 13-03005, 14-02040, 14-02041, 14-02042, 15-02039, 15-02040, 15-02041, 16-03003, 16-03004, 16-03005, 17-03001, 17-03002, 17-03003, 18-03002, 18-03003, 18-03004, 19-03001, 19-03002, 19-03003, 20-02026, 20-02027, 20-02028, 21-03005, 21-03006, 21-03007, 22-03001, 22-03002, 22-03003, 23-03005, 23-03006, and 23-03007).

Prior to joining the Energy Practice, I was a member of NERA's Securities and Finance Practice. **Exhibit-Strunk-Direct-1** contains a more detailed statement of my qualifications.

II. PURPOSE OF TESTIMONY AND FINDINGS

3. Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to present my opinions on the prudence of the Company's physical natural gas commodity transactions from January 1, 2023, through December 31, 2023 (the "Deferral Period"). These transactions were made in order to supply fuel to the Company's natural gas-fired generation facilities and to serve local distribution loads.

4. Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Public Utilities Commission of Nevada ("Commission") must evaluate whether the natural gas commodity purchases meet the prudence standard and were reasonably entered into in connection with the discharge of the Company's public duties. I address the question of prudence taking into consideration the applicable Nevada statutes, applicable regulatory precedent, and the market conditions that prevailed during the period when the Company executed its transactions. My review of the Company's physical natural gas procurement activities indicates that:

- The Company followed the four-season laddering strategy for natural gas procurement elaborated in its 2022-2041 Triennial Integrated Resource Plan ("IRP") and the 2023-2024 Energy Supply Plan ("ESP") Update. The Commission approved the IRP and ESP in Docket No. 21-06001 and the ESP updates in Docket Nos. 22-09002 and 23-09003. For gas deliveries during the Deferral Period, the Company maintained the same strategy, which allows the Company to lock in the availability of physical gas using forward contracting beginning four seasons in advance of delivery. The Company, thus, structures its procurement approach around seasonal needs and the gradual filling of those needs at prices indexed to the prevailing market.

- In its seasonal gas requests for proposals ("RFPs"), the Company implemented reasonable procedures to solicit bids from prospective suppliers and followed a reasonable approach to evaluate those bids.
- The Company used appropriate procurement practices to fill monthly, daily, and other short-term gas needs.
- The quantities of physical natural gas procured were reasonable and consistent with the Company's needs.
- The prices paid for physical natural gas were either explicitly indexed to market or were fixed at levels consistent with prevailing market conditions.
- The mix of products relied upon by the Company was appropriate for its needs and was consistent with those foreseen in its Commission-approved ESP and ESP updates.
- No financial hedges were transacted for the Deferral Period. The Company continued to hold workshops on gas procurement with the Regulatory Operations Staff and the Bureau of Consumer Protection in which hedging was considered. The Company reasonably elected not to execute financial hedges for the Deferral Period.

In sum, I find that these natural gas procurement activities are reasonable and consistent with the Company's obligations to provide reliable electric service to customers. The transactions themselves are reasonable as they were part of a well-considered gas procurement plan that reflected considerable stakeholder input and was approved by the Commission. The implementation of the transactions was reasonable as well. The Company purchased prudent quantities of gas and paid prices that were either explicitly indexed to market or were fixed at levels consistent with prevailing market conditions. These facts lead me to the conclusion that the costs sought by the Company for natural gas procurement activities have been prudently incurred.

III. DESCRIPTION OF THE STANDARD AGAINST WHICH THE PRUDENCE OF PROCUREMENT ACTIVITIES MUST BE JUDGED

5. Q. ARE THE COMPANY'S GAS COSTS SUBJECT TO A PRUDENCE REVIEW UNDER NEVADA LAW?

A. Yes. Under NRS § 704.110, the Commission:

> [S]hall not allow the public utility to recover any recorded costs of natural gas which were the result of any practice or transaction that was unreasonable or was undertaken, managed or performed imprudently by the public utility, and the Commission shall order the public utility to adjust its rates if the Commission determines that any recorded costs of natural gas included in any quarterly rate adjustment or the annual rate adjustment application were not reasonable or prudent.

6. Q. PLEASE DESCRIBE THE STANDARD TO BE APPLIED TO DETERMINE THE PRUDENCE OF NATURAL GAS PROCUREMENT ACTIVITIES.

A. To judge whether a utility's decision making is prudent, regulators use what is known as the reasonable person standard.[1] They ask whether the decisions made by the utility are within the possible set of decisions that a reasonable person could have made given the information reasonably knowable at the time. The New York Public Service Commission has characterized the standard as follows:

> [T]he company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company.[2]

Ultimately, the regulator must determine whether the decision resulted in "a reasonable and prudent business expense, which the consuming public may reasonably be required to bear?"[3] The Commission and the Nevada Supreme Court have articulated the prudence standard similarly.

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[1] *See, e.g.*, Leonard Saul Goodman, *The Process of Ratemaking, Vol II,* 858 (1998).
[2] *In re Consolidated Edison Co. of N.Y. Inc*., Opinion no. 79-1, 1979 WL 415126 (N.Y.P.S.C. Jan. 16, 1979).
[3] *Midwestern Gas Transmission Co. v. F.P.C.*, 388 F.2d 444 (1968).

7. Q. DO YOU EVALUATE THE COMPANY'S PHYSICAL NATURAL GAS TRANSACTIONS AGAINST THIS REASONABLE PERSON STANDARD?

A. Yes, this standard has guided my review of the reasonableness of the Company's decision-making processes and its implementation of natural gas transactions.

IV. SCOPE OF THE REVIEW PROCESS

8. Q. PLEASE DESCRIBE THE NATURE OF THE REVIEW PROCESS YOU UNDERTOOK IN ORDER TO REACH THE CONCLUSIONS YOU MAKE REGARDING THE PRUDENCE OF THE PHYSICAL NATURAL GAS TRANSACTIONS ENTERED INTO BY THE COMPANY.

A. My review process was performed in two phases. The first consisted of gathering information about the Deferral Period transactions. The second involved developing an independent qualitative and quantitative analysis to verify the reasonableness of the transactions. Specifically, during the first phase, I performed the following tasks:

- Gather relevant documentation on natural gas procurement for the Deferral Period, including transaction data, relevant regulatory filings, Risk Committee meeting minutes, internal policies and procedures, and documentation for seasonal RFPs; and
- Conduct interviews with the staff who manage and oversee natural gas procurement for the Company.

During the second phase, my focus turned to these additional tasks:

- Review the analysis that is performed by the Company prior to trade execution for seasonal RFPs;
- Discuss with traders the execution process for monthly and daily natural gas transactions and reviewing transaction plans and trader logs for the Deferral Period;

- Analyze the reasonableness of prices paid in physical natural gas transactions with Deferral Period deliveries;
- Assess the reasonableness of quantities transacted for natural gas during the Deferral Period; and
- Evaluate the reasonableness of the products chosen by the Company to fill its needs.

V. OVERVIEW OF THE COMPANY'S NATURAL GAS PROCUREMENT FOR THE DEFERRAL PERIOD

9. Q. PLEASE DESCRIBE SIERRA'S NATURAL GAS PROCUREMENT PROGRAM.

A. Seasonal forward natural gas purchases for the Deferral Period reflect the four-season laddering strategy approved in Docket No. 15-07004 and in subsequent ESP filings. I illustrate the timing of transaction execution relative to the delivery of natural gas in **Table Strunk Direct 1** below.

Table Strunk Direct 1

		Delivery Period		
		Winter 2022/23	Summer 2023	Winter 2023/24
Transaction Execution	Winter 2020/21	25%		
	Summer 2021	25%	25%	
	Winter 2021/22	25%	25%	25%
	Summer 2022	25%	25%	25%
	Winter 2022/23		25%	25%
	Summer 2023			25%

This approved four-year laddering strategy drove the Company's implementation of seasonal forward natural gas purchases for the Deferral Period.

In addition to seasonal purchases, the Company relied upon transactions in the monthly and spot markets to balance its needs as the expected gas burn for its electric generation facilities and distribution loads evolved in response to changing load and market conditions. Throughout the Deferral Period, the Company participated in the Energy Imbalance Market ("EIM"), operated by the California Independent System Operator ("CAISO"). As a result, gas balancing activity included activities driven by the Company's participation in the EIM and responses to CAISO instructions.

10. Q. PLEASE SUMMARIZE THE PURCHASES MADE IN THE DIFFERENT MARKETS.

A. **Table Strunk Direct-2** below depicts the net quantities of natural gas purchased in each market.

Table Strunk-Direct-2

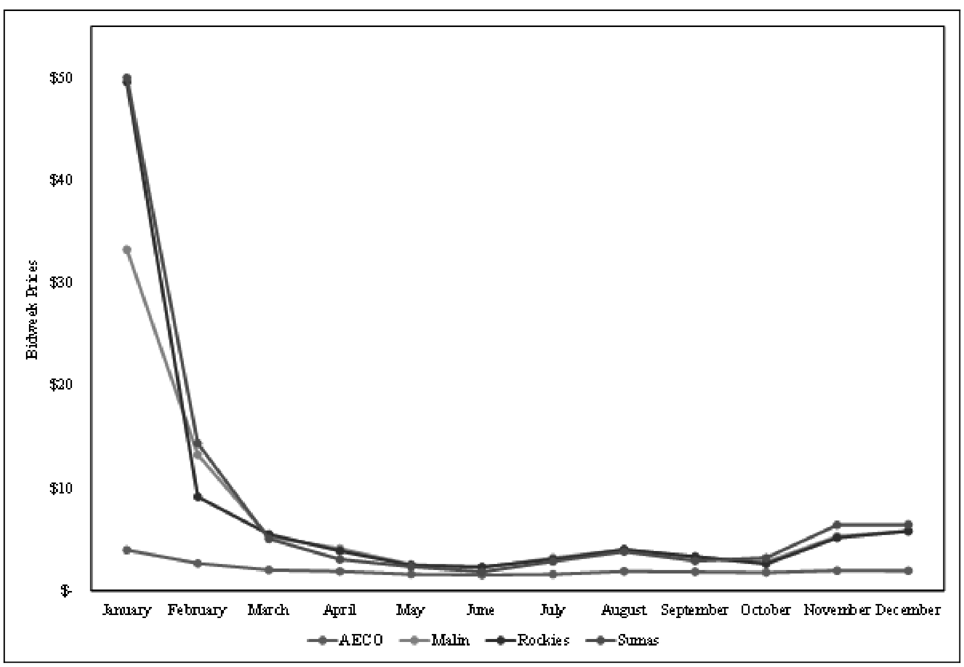
		Procurement			
		Seasonal	Monthly	Spot	Total MMBtu
Delivery Month	January	5,518,000	82,708	1,464,430	7,065,138
	February	4,872,000	-	1,267,619	6,139,619
	March	4,479,500	-	1,333,269	5,812,769
	April	3,615,000	-	382,822	3,997,822
	May	3,658,000	-	359,500	4,017,500
	June	3,615,000	-	(362,512)	3,252,488
	July	4,805,000	-	(236,755)	4,568,245
	August	4,417,500	-	(672,496)	3,745,004
	September	3,840,000	-	(145,159)	3,694,841
	October	4,185,000	-	622,190	4,807,190
	November	4,710,000	-	504,591	5,214,591
	December	5,533,500	-	846,698	6,380,198

VI. MARKET DYNAMICS AFFECTING NATURAL GAS COSTS FOR THE DEFERRAL PERIOD

11. Q. WAS THERE TURMOIL IN THE WESTERN NATURAL GAS MARKETS IN ANY OF THE DEFERRAL PERIOD DELIVERY MONTHS?

A. Yes. During the 2023 Deferral Period, the January natural gas prices faced by the Company stand out as reflecting significant tightness and turmoil in the Western markets. Natural gas commodity prices were particularly high in January, but fell beginning in February for the remainder of the Deferral Period. **Figure Strunk-Direct-1** shows the bidweek prices at gas trading hubs relied upon by the Company.

Figure Strunk-Direct-1: 2023 Bidweek Prices[4]



[4] January 2023 FERC First of Month Report (January Rockies) and SNL Energy, a division of S&P Capital IQ.

Several occurrences contributed to higher prices in January 2023.

- The first is lower-than-normal temperatures in December 2022. The cold temperatures led to increased natural gas heating demand[5] and pushed up prices during the December 2022 bidweek, at which time monthly prices for January 2023 delivery were established.
- Second, natural gas flows, hindered by reduced pipeline capacity due to maintenance in West Texas,[6] could not keep up with higher consumer demand, and led to constraints for shippers moving gas to the west out of Permian. According to S&P Global, the western United States relied heavily on gas flows from Canada in mid-January to make up for the reduced flows; the Pacific Northwest received record-high flows from Western Canada.[7] These events pushed up pricing at hubs where the Company buys gas.
- Third, natural gas storage inventories were also below the five-year average in in December 2022.[8]

Platts, which publishes the Inside FERC bidweek prices, relies upon observed prices during the last five business days of each month for monthly transactions with delivery during the next month.[9] January 2023 prices were therefore set during the last week of December when daily prices were especially high.[10] The cold weather and flow disruptions created supply

[5] *See* EIA, "U.S. natural gas consumption reached record daily high in late December 2022," January 31, 2023.
[6] Riley Simpson, CompressorTECH^2, "Western U.S. natural gas reaches highest spot prices since 2000," January 4, 2023.
[7] *See* S&P Global, "US West gas prices whiplash again, contributing to historic shifts in regional flows," January 13, 2023.
[8] *See* EIA, "Natural Gas Weekly Update for week ending December 21, 2022," December 22, 2022.
[9] S&P Global, Methodology and Specifications Guide US and Canada Natural Gas, p. 5.
[10] *See* Historical Spot Price Data obtained from SNL Energy, a division of S&P Capital IQ, included as part of my workpapers.

constraints and above-average pricing at the end of December, thereby increasing pricing pressure on January 2023 forward contracts. Furthermore, low storage inventory continued into January, thus also putting upward pressure on January spot prices in the daily market.[11]

S&P Global analysts Eric Brooks and Felix Clevenger explained the lower levels of storage inventories, "The market continues to be wary of weak storage levels and the ongoing dependence on supply from connecting regions. There is only so much gas that can reach the West from the Permian."[12]

Taken together, the reduced natural gas to the west from the Permian basin, along with lower-than-average natural gas storage, rising domestic natural gas consumption, and natural gas pipeline constraints were key factors resulting in abnormally higher gas prices in the Western U.S. These higher gas prices led to higher gas costs for the Company in January of the Deferral Period.

12. Q. COULD THE COMPANY HAVE AVOIDED THE HIGHER COSTS OF GAS IT FACED IN JANUARY OF THE DEFERRAL PERIOD?

A. No. The Company's approved procurement strategy depends on market-based purchases of natural gas. The Company's costs will naturally be higher when market prices are high. The Company was also able to benefit from lower market prices for natural gas during the remainer of the Deferral Period.[13]

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[11] *See* S&P Global, "US West gas prices whiplash again, contributing to historic shifts in regional flows," January 13, 2023.
[12] *Ibid*.
[13] I note, however, that bidweek pricing for February remained at above-average levels, although it was not nearly as extreme as January.

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

VII. PRODUCT PORTFOLIO

13. Q. WAS THE PRODUCT PORTFOLIO CHOSEN BY THE COMPANY APPROVED BY THE COMMISSION?

A. Yes. The Commission approved the product portfolio in connection with the approval of the Company's IRP in Docket No. 21-06001 and ESP updates in Docket Nos. 22-09002 and 23-09003. The Company's product portfolio tracks the portfolio that had been approved by the Commission in these plans.

14. Q. IS THE PHYSICAL NATURAL GAS PRODUCT PORTFOLIO RELIED UPON BY THE COMPANY FOR THE DEFERRAL PERIOD REASONABLE AND PRUDENT?

A. Yes, it is. Procuring physical forward contracts using a buy-over-time strategy that begins the procurement process four seasons in advance assures the physical availability of natural gas to fire the Company's power generation facilities and to serve customers taking local gas distribution service. Tying the pricing of such contracts to index means that ratepayers are not subject to out-of-market costs for natural gas. Given the variability in the volumes needed by the Company, the use of index products is particularly advantageous. Index products limit the financial exposure associated with holding a long or short position as expected gas burns change over time.

15. Q. DID THE COMPANY APPROPRIATELY RELY UPON SHORTER-TERM MARKETS TO BALANCE ITS PHYSICAL NATURAL GAS NEEDS OVER TIME?

A. Yes, it did. As noted above, the Company relied on monthly and shorter-term spot markets to balance its natural gas needs.

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

16. Q. DID THE COMPANY USE STANDARD FORM CONTRACTS WHEN PROCURING PHYSICAL NATURAL GAS?

A. Yes, when structuring its contractual arrangements with counterparties, the Company relied upon the North American Energy Standards Board's standard contract, the International Swaps and Derivatives Association's North American Gas Annex designed for physical gas transactions, and the Gas EDI Base Contract for Short-Term Sale and Purchase of Natural Gas. Insofar as the Company entered into transactions at the Alberta Hub, it required a Canadian addendum (or equivalent) to these standard agreements.

17. Q. PLEASE SUMMARIZE YOUR OPINION ON THE CHOICE OF PRODUCT PORTFOLIO.

A. The Company prudently filled its natural gas needs using the product portfolio outlined in its ESP and ESP updates, which were approved by the Commission. Its product portfolio includes primarily index products, which provide reliability benefits while not risking excessive financial exposure. The Company employed industry-standard contract terms when procuring gas. These facts lead me to the conclusion that the Company's choice of product portfolio was prudent.

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

VIII. EXECUTION OF NATURAL GAS TRANSACTIONS FOR THE DEFERRAL PERIOD

A. RFPs for Seasonal Transactions

18. Q. PLEASE DESCRIBE HOW THE COMPANY IMPLEMENTED ITS PROCUREMENT OF SEASONAL PURCHASES FOR THE DEFERRAL PERIOD.

A. The Company procured seasonal natural gas using competitive bidding processes. The Company sent RFPs to an established set of pre-approved counterparties and asked those counterparties to provide pricing for the various products needed. Bidders were instructed to complete a spreadsheet bid response form, which allowed them to indicate important bid data such as the delivery point, delivery period, maximum volume available, and the premium or discount bid relative to the index.

19. Q. HOW DID THE COMPANY EVALUATE BIDS?

A. The Company relied upon a spreadsheet model designed to select the most economic bids subject to constraints such as limits on transport capacity and limits on the amount of gas taken at each delivery point. The spreadsheet model includes a linear programming optimization that seeks to identify the combination of bids that yields the lowest delivered cost of gas for the Company's customers. Since the bids are structured with an "up to" maximum volume, the linear program selects the quantity of each that is optimal given the specified constraints.

20. Q. DID THESE RFPS RESULT IN COMPETITIVE PRICING FOR THE PHYSICAL GAS PRODUCTS PROCURED BY THE COMPANY?

A. Yes. Prices for the seasonal natural gas transactions entered into by the Company were disciplined by the competition that took place within the RFP process. Since the transactions at issue were priced at index, the primary source of competition was around the premium or discount to the index price at which the natural gas would trade.

21. Q. DID THE QUANTITIES PROCURED IN THE RFPS TRACK THE LADDERING STRATEGY APPROVED BY THE COMMISSION?

A. Yes. They did. The minutes of the risk committee meetings, including the PowerPoint decks presented at those meetings, confirm that the volumes tracked the approved laddering strategy.

B. Premiums for Seasonal Transactions

22. Q. DID A CAP APPLY TO THE PREMIUM PAID ON PHYSICAL GAS TRANSACTIONS?

A. Yes. The Company's transactions were subject to a premium cap, which could only be exceeded with approval from the Risk Committee.

23. Q. WAS THE CAP EXCEEDED FOR ANY DEFERRAL PERIOD TRANSACTIONS?

A. Yes. Seasonal purchases for the deferral period (59 of 134 seasonal purchases entered into for 2023 deliveries) exceeded the cap owing to market conditions for forward physical transactions at the delivery points solicited by the

Company. The Company's analysis shows that the transactions executed with premia above the cap were the least-cost alternatives available to it.

I note that the premium or discount over bidweek differs by pricing index. The Company did not pay a premium over bidweek on seasonal transactions priced at the AECO (Alberta) bidweek index. Similarly, the Company received, on average, a discount relative to bidweek for transactions priced at Sumas, and paid, on average, a premium for Rockies and Malin bidweek transactions.

24. Q. IS THE LEVEL OF THE PREMIUM CAP THAT THE COMPANY USES OUT OF SYNC WITH PREVAILING CONDITIONS IN THE NATURAL GAS MARKETS?

A. Yes, it is. The Company agreed to implement a cap on premiums paid for physical natural gas transactions as part of a Stipulation on energy supply issues in Docket No. 09-07003.[14] The Commission held, in its April 2, 2010, Order in that same docket, that the Energy Supply Plan Stipulation was in the public interest.[15] The premium cap was established at that time, now 14 years ago. Since then, there has been no adjustment to the cap for inflation or for changing market conditions.

Changes to the configurations of pipeline capacity in the Pacific Northwest and the Rockies have affected supply and demand in the region and had concomitant effects on pricing.

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[14] Stipulation dated March 16, 2010, p. 4, Paragraph 17.
[15] Order dated April 2, 2010, p. 4, Paragraph 22.

As I explain below, the Company's competitive RFP results, evidence on market pricing at different hubs within the Rockies, and energy analyst commentary demonstrate that the Company's cost of gas reasonably reflects market-based premia and discounts relative to the bidweek prices to which the Company ties the pricing of Seasonal RFP transactions. The premium established fourteen years ago is, particularly for the Rockies and Malin bidweek indices, no longer reflective of the current gas market the Company faces.

25. Q. TAKING A STEP BACK, PLEASE EXPLAIN WHY THE COMPANY HAS TO PAY A PREMIUM RELATIVE TO INDEX PRICING FOR SEASONAL TRANSACTIONS IN THE FIRST PLACE?

A. A premium or discount to the bidweek price is a fundamental and longstanding component of term natural gas market transactions. When traders rely on a bidweek price, they often include a premium to be paid above the index value and in some circumstances incorporate a discount. As an economic matter, the premium (or discount) can reflect multiple factors, including supply or demand pressures, the cost of transportation, market participant preferences, and other factors. Below I address several factors that influence the degree to which a specific transaction's price differs from the bidweek price.

26. Q. WHICH FACTORS DO YOU ADDRESS THAT CAN EXPLAIN THE PREMIUM OR DISCOUNT TO BIDWEEK PRICE THAT SELLERS REQUIRE?

A. First, I address the fact that the premium or discount can be attributable to sellers' and buyers' risk preferences and the need to balance the supply and demand for a given product. Second, I consider the existence of specific costs that the supplier of gas may face – geographic or otherwise – that are not incorporated in the index. Third, I explain that the premium may simply reflect a higher-than average value of gas at a delivery point as compared to the average value across all delivery points used in formation of the bidweek price.

27. Q. HOW CAN RISK PREFERENCES HELP TO EXPLAIN THE NEED FOR A PREMIUM OR DISCOUNT RELATIVE TO THE BIDWEEK PRICE?

A. Risk preferences help to explain the premium or discount because a seller of gas may prefer to trade in one market over another. For example, a producer or seller of gas may prefer to wait and place all of its supply in the spot market if the producer believes supply and demand conditions will be tight and will yield average prices above the level set at bidweek. Producers or sellers with a preference for trading spot may be unwilling to enter transactions priced at bidweek unless they receive a high premium to compensate them for expected foregone profit in the spot market. On the other hand, producers or sellers who do not want the volatility and risks associated with the daily markets will prefer trading bidweek and may even offer a discount for being able to lock in a single price for all volumes traded in that month. Similar dynamics are at play for buyers of gas.

Risk preferences can therefore be an important factor in determining premiums, particularly in volatile markets. Because natural gas markets are highly competitive, the trading process reveals the relative risk preferences of buyers and sellers of gas and reveals the premium or discount needed to equilibrate supply and demand.

28. Q. YOU MENTIONED A SECOND FACTOR THAT MAY AFFECT PREMIUMS, *I.E.*, THAT SOME SELLERS FACE HIGHER COSTS. HOW DOES THAT AFFECT THE PREMIUM?

A. Yes, that is the second factor I consider. Some sellers face costs that are not faced by sellers of forward contracts in the bidweek market. For example, a gas producer or a gas trader may have to move gas over a gathering system or pipeline system in order to get gas to the delivery point foreseen in a given transaction and thus may face higher costs than other sellers of gas making trades that deliver to the delivery points that were considered to establish the bidweek price. Additionally, the seller could be trading at the bidweek price but delivering to a pipeline point not considered in the fixing of the bidweek index price. In such cases, that gas seller will need to recover its additional costs in a premium over the bidweek price.

29. Q. EVEN IF SELLERS FACE THE SAME COSTS TO MOVE GAS OVER PIPELINES, MIGHT THE PREMIUM BE ATTRIBUTED TO OTHER FACTORS?

A. Yes. The third factor I address is the possibility that a given transaction requires a premium to bidweek simply because it prescribes delivery at a delivery point that has a higher value than the average bidweek delivery point. Because the trades used to establish the bidweek price cover forward contracts for gas delivery at many different delivery points, some delivery points will naturally reflect higher pricing, while others will reflect lower pricing. Gas sellers that make trades at delivery points that command a premium will need to charge more relative to the index price than those that make trades at delivery points with lower-than-average pricing. Premiums and discounts, therefore, can simply reflect higher or lower value delivery points on the pipeline networks relative to the average used in the bidweek price.

30. Q. TO WHICH INDICES DOES SIERRA TIE ITS SEASONAL PURCHASES PRICED AT BIDWEEK?

A. Sierra ties its trades to Inside FERC Rockies, Inside FERC Sumas, NGI Malin, and Platts CGPR AECO.

31. Q. HOW DOES PLATTS DETERMINE THE INSIDE FERC BIDWEEK PRICES THE COMPANY FACES?

A. Platts canvasses market participants during the last five business days before the start of the contract month[16] for trades that deliver to the delivery points it

[16] S&P Global, Methodology and Specifications Guide US and Canada Natural Gas, p. 5.

deems relevant for the particular index. For example, for the Inside FERC Rockies bidweek price, Platts examines trades that deliver to Northwest Pipeline's mainline from Green River, Wyoming compressor station to the Kemmerer, Wyoming station. Deliveries take place at the Opal Plant as well as at the Painter, Anschutz, Muddy Creek, Granger, Shute Creek, Pioneer Plant and Whitney stations on trades tied to Inside FERC Rockies.[17] Trades tied to the Inside FERC Sumas price deliver into the Northwest Pipeline from Westcoast Energy at the Sumas, WA.-Huntington, British Columbia, interconnection at the US-Canadian border.[18] Platts publishes a bidweek price based on an average of the pricing for trades at the various delivery points canvassed.

32. Q. DOES THE INSIDE FERC BIDWEEK PRICE CAPTURE A VARIETY OF PRICING CONDITIONS ACROSS MULTIPLE LOCATIONS?

A. Yes. It does. The Inside FERC Rockies is a good example. While the bidweek price includes trades at delivery points in Southwest Wyoming, the inclusion of pricing for delivery points in Colorado and Utah means that the geographic representation is broad. To the extent that the Wyoming Pool meter where the Company buys gas is a higher-value delivery point, then the premium paid over bidweek will capture that fact.

33. Q. DOES NGI FOLLOW A SIMILAR PROCESS FOR MALIN?

A. Yes, it does. The NGI Index is for trades with deliveries from TC Energy's GTN Pipeline and El Paso/Kinder Morgan's Ruby Pipeline into PG&E's

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[17] S&P Global, Methodology and Specifications Guide US and Canada Natural Gas, pp. 15-16.
[18] S&P Global, Methodology and Specifications Guide US and Canada Natural Gas, p. 15.

Redwood Path at Malin, Oregon.

34. Q. WHAT ABOUT PLATTS CGPR AECO?

A. This index too is based on deliveries to multiple points on the pipeline system. Platts CGPR AECO bidweek index captures deliveries into TC Energy's Alberta System at the AECO-C, NIT Hub in southeastern Alberta. AECO-C is the principal storage facility and hub on TCPL Alberta; paying the rate for NIT service, or Nova Inventory Transfer, will cover transmission for delivery of gas to AECO-C and most other points.

35. Q. WHAT EVIDENCE HAVE YOU REVIEWED TO VERIFY THAT THE COMPANY'S DELIVERY POINT COMMANDS A PREMIUM RELATIVE TO THE INSIDE FERC ROCKIES BIDWEEK PRICE?

A. I note first that energy analyst commentary confirms price dispersion within the Rockies market. Rishi Rajanala, analyst at Aegis Energy, explained: "There is a constraint for gas produced on the eastern Rockies to flow westward; therefore, NWP-Rox can trade at a material premium to CIG when there is an acute need for gas in the west and PacNW markets."[19]

Two other data sources confirm that the Company's delivery point is a premium delivery point. First, I reviewed the Company's RFP results, which demonstrate that sellers require a premium to make delivery at the delivery location where the Company requires gas. Second, I reviewed price data for a variety of points in the Rockies gas market. Those pricing points that more

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[19] *See* Rishi Rajanala, "Rockies Price and Fundamentals," January 11, 2024.

closely represent the geographic region where the Company buys gas indicate a higher value than the Inside FERC Rockies during the Deferral Period. Note that, for the month of January 2023, the Inside FERC Rockies Index used by the Company was $49.57/MMBtu, whereas the bidweek price for the Wyoming Pool (a more geographically proximate trading hub) was $52.56/MMBtu. Importantly, both bidweek prices reflected an average of trades that had wide price dispersion. The Inside FERC Rockies Index was based on trades that ranged from $26.00 to $58.50 per MMBtu. Similarly, the Wyoming Pool reflected an average of trades that were priced in the range of $33.00 to $58.50 per MMBtu. While some of the observed price dispersion likely reflects changing conditions over the bidweek pricing period, it is reasonable to expect value differences across delivery points also contributes to the wide range of pricing used to determine the bidweek index price.

36. Q. ARE THE PREMIA PAID ON SEASONAL TRANSACTIONS AT MALIN ALSO REASONABLE?

A. Yes. As noted, I reviewed the Company's RFP documentation and bid evaluation spreadsheets and linear program optimization. The documentation confirms that the RFP was subject to the discipline of competition. The premia reflect real requirements of sellers based on the specific gas market dynamics in the Pacific Northwest and the delivery terms of the Company's trades.

37. Q. IN SUM, WERE THE PREMUMS PAID BY THE COMPANY ON PHYSICAL GAS TRANSACTIONS PROCURED THROUGH SEASONAL RFPS REASONABLE?

A. Yes. The Company transactions were subject to the competitive discipline of the RFP process. Additionally, my review of market data and energy analyst commentary corroborates the reasonableness of Sierra's seasonal transactions and the premiums paid.

C. Monitoring

38. Q. DID THE COMPANY MONITOR THE PROCUREMENT QUANTITIES?

A. Yes. The Company had in place a monitoring program and policies to assure that any shortfall or surplus in the amount of natural gas procured for a given month would be met through the bidweek or daily markets. The Company periodically updated its projected gas burns. In the event of significant changes to the gas burn forecast, Resource Planning was required to seek approval from the Risk Committee to update the target "procure to" levels for any given month. My review of the Company's Risk Committee presentations indicates that the Company did reasonably monitor its positions over time and did seek changes to the "procure to" levels when the expected gas burn significantly exceeded or fell short of that approved level. During the year, in February 2023 and August 2023, the Risk Committee approved new "procure to" quantities which were reflected in the March 2023 and September 2023 monthly updates, for the Company in anticipation of the issuance of seasonal RFPs.

In addition, in the periods leading up to the gas flow dates, the Resource Optimization department monitored gas positions to assure that the Company remained within a tolerance band around the projected gas burn. When the Company's short or long position was outside the tolerance band, it made trades to bring it back within the band. For example, Resource Optimization found itself outside the band in certain months during the Deferral Period (including the months of March, April, July, August, and September of 2023). In its transaction plans, the Company determined that no action was needed in the forward market. With the exception of one monthly trade for January priced at Gas Daily, the Company planned on using spot trades to balance its needs with its contracted supply of gas.

D. Balancing Monthly and Spot-Market Transactions

39. Q. HOW DID THE COMPANY IMPLEMENT THE MONTHLY AND SPOT MARKET TRANSACTIONS DURING THE DEFERRAL PERIOD?

A. The Company's traders were responsible for executing transactions that balance its portfolio. As discussed above, the Company's policies call for active monitoring of its positions and the balancing of its contracted volumes with gas burns in either the monthly market or spot-market. These personnel actively monitored and participated in the markets for natural gas in the Rockies and the Northwestern United States. They used electronic trading platforms such as the Intercontinental Exchange that are widely relied upon by the industry. They also made direct contact with counterparties to effect transactions, typically using instant messaging.

40. Q. ARE THESE EXECUTION STRATEGIES REASONABLE?

A. Yes, they are reasonable. They reflect how physical natural gas is traded in the industry for monthly and shorter-term delivery horizons.

41. Q. HAVE YOU ANALYZED INDEPENDENT DATA TO CONFIRM THE REASONABLENESS OF THE EXECUTION PRICES ACHIEVED BY THE COMPANY FOR ITS BALANCING TRADES?

A. Yes, I have. I was able to compare the prices at which the Company transacted for standard daily gas to the range of prices that were reported by S&P Capital IQ Pro for those trading hubs where significant market activity can be observed. For some natural gas hubs, S&P Capital IQ Pro reports its own pricing; for others, S&P Capital IQ Pro relies upon data that it procures from NYMEX, brokers, and other sources. The S&P Capital IQ Pro data provides an indicator of the range of prices that were being paid by others for similar transactions. On balance, the execution prices received by the Company compare reasonably to these indicators of market pricing for similar products. My comparison to market is shown in **Exhibit Strunk Direct 2**.

42. Q. IN SUM, WAS THE COMPANY'S IMPLEMENTATION OF ITS PHYSICAL GAS PROCUREMENT PROGRAM REASONABLE?

A. Yes, it was. As noted, the Company purchased reasonable quantities of natural gas in connection with a Commission-approved procurement strategy and in connection with the Company's duties to its customers. The aggregate dollar amounts the Company seeks to recover are reasonable. The Company used competitive procurements to implement the seasonal purchases and industry-appropriate execution strategies for shorter-term transactions, resulting in reasonable execution prices. Based on this fact pattern, I conclude that the applied-for physical natural gas procurement costs are reasonable and prudent expenditures.

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

A. Yes.

EXHIBIT STRUNK-DIRECT-1

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KURT G. STRUNK
Senior Managing Director

Mr. Strunk is an expert in applied finance and energy matters with 30 years of experience in international arbitration, complex commercial litigation, and regulatory proceedings. Mr. Strunk is recommended as a leading energy expert by *Who's Who Legal*. He has been retained as an expert to testify in arbitrations before the London Court of Arbitration, ICSID, the International Institute for Conflict Prevention & Resolution, the American Arbitration Association, and *ad hoc* international arbitration. He has testified before energy regulatory commissions, tax court, and bankruptcy court. His testimonies have addressed a range of issues, including construction delay, industry practice, asset and contract valuation, breach-of-contract damages, the proportionality of stipulated liquidated damages provisions, cost of capital and discount rates, tariffs, regulatory accounting, regulatory reform, trading and risk management.

In the oil and gas sectors, Mr. Strunk has consulted on rate matters, mergers and acquisitions, restructurings, contract disputes, valuation, trading, risk management, and product pricing. He has valued oil and gas assets and contracts in litigated disputes on behalf of major firms in the petroleum sector. He advised sellers of LNG in disputes with buyers (prior to international arbitration) and performed extensive quantitative analysis around appropriate prices and damages in the event of a breach. He has served as an expert in regulatory hearings relating to pipeline tariffs in Canada and the United States. He has also carried out studies of the reasonableness of gas supply agreements in various jurisdictions and quantified damages in connection with the early termination of such agreements.

In electric power, Mr. Strunk has advised governments, regulators, and energy companies on industry structure, regulation, and sector reform in North America, South America, Europe, Australia, Asia, and Africa. In generation, his assignments often involve analysis of new and existing power generation resources and supply contracts. He has advised clients on the procurement of green power and green certificates. He has worked side-by-side with counsel on the development of independent power contracts and competitive solicitations across the globe. He served as a key member of NERA's team advising on electric sector reform and power market design in Spain and Mexico, projects he carried out in the Spanish language. He routinely values electricity sector companies and assets in the context of disputes and advisory assignments.

Mr. Strunk's assignments often require that he determines the appropriate return on equity capital for energy firms. He has calculated and supported required rates of return for power generators, gas distribution utilities, electric distribution and transmission companies, and other energy firms in the context of traditional tariff reviews for regulated entities, litigation, and advisory work. Mr. Strunk frequently collaborates with NERA's Securities and Finance Practice. He has addressed liability and damages in broker-dealer disputes, and in securities class actions.

Education

1997	**INSEAD (The European Institute of Business Administration), Fontainebleau, France** MBA, with Distinction, 1997
1993	**VASSAR COLLEGE, New York, USA** B.A., Economics, General and Departmental Honors

Career Details

1993-present	**NERA ECONOMIC CONSULTING** Current position Managing Director, New York
1992	**GÉNÉRALE DE BANQUE** Research Assistant, Brussels

Languages

English: mother tongue
French: fluent
Spanish: fluent

Project Experience

EXPERT TESTIMONY (2019 – present)

2023 **Confidential Client**

Trial testimony before the London Court of Arbitration addressing industry and market conditions and damages from an alleged breach of contract in a high-stakes oil & gas dispute between parastatal Latin American company and US investment firm.

November 9, 2023 and November 10, 2023

2023 **Court Proceeding**

Deposition testimony on matters relating to the business outlook of a PADD 1 refinery during the COVID-19 pandemic.

October 3, 2023

2023 **Court Proceeding**

Deposition testimony on custom and practice in the power industry and damages suffered by a buyer of power as a result of an alleged breach of a power supply agreement.

August 16, 2023

2023 **Court Proceeding**

Deposition testimony on custom and practice in the power industry and damages suffered by a buyer of power as a result of an alleged breach of a power supply agreement.

July 12, 2023

2023 **Court Proceeding**

Deposition testimony on the valuation of a power generation facility and the damages owing to a minority owner from contract breaches by the majority owner and operator.

June 16, 2023

2023 **Court Proceeding**

Deposition testimony on damages attributable to an allegedly unlawful failure to terminate an energy supply agreement.

April 25, 2023

2023 **Court Proceeding**

Rebuttal expert report on damages attributable to an allegedly unlawful failure to terminate an energy supply agreement.

April 20, 2023

2023 **Court Proceeding**

Rebuttal expert report on the valuation of a power generation facility and the damages owing to a minority owner from contract breaches by the majority owner and operator.

April 14, 2023

2023 **Court Proceeding**

Rebuttal expert report on damages attributable to an allegedly unlawful failure to terminate an energy supply agreement.

April 10, 2023

2023 **NV Energy**
Gas Trading / Prudence

Direct Testimony before the Nevada Public Utilities Commission, on behalf of Nevada Power Company, examining whether the trades in its natural gas trading book were prudent.

March 1, 2023

2023 **NV Energy**
Gas Trading / Prudence

Direct Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, examining whether the trades in its natural gas trading book were prudent.

March 1, 2023

2023 **Court Proceeding**

Expert report on damages on damages attributable to an allegedly unlawful failure to terminate an energy supply agreement.

February 20, 2023

2023 **Court Proceeding**

Expert report on the valuation of a power generation facility and the damages owing to a minority owner from contract breaches by the majority owner and operator.

February 10, 2023

2023 **Federal Energy Regulatory Commission**

Affidavit on behalf of United Power, Inc. before the Federal Energy Regulatory Commission in Docket No. ER20-681 commenting on the effect of member withdrawals on Tri-State G&T's uncommitted capacity and horizontal market power screening analysis for market-based sales in the WACM Balancing Authority Area.

January 6, 2023

2022 **British Columbia Utilities Commission**
Pricing of Renewable Gas

Pre-filed Testimony before the British Columbia Utilities Commission addressing policies to attract renewable gas, efficient price signals, and non-discrimination in the establishment of tariffs.

December 5, 2022

2022 **NV Energy**
Cost of Capital

Oral Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, on the cost of capital.

September 28, 2022

2022 **NV Energy**
Cost of Capital

Rebuttal Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, presenting analysis on the cost of capital.

September 21, 2022

2022 **NV Energy**
Cost of Capital

Direct Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, presenting analysis on the cost of capital.

June 1, 2022

2022 **Federal Energy Regulatory Commission**

Affidavit addressing the proposed resolution of the Buy-down Payment methodology for terminating the Wholesale Electric Service Contract between Tri-State Generation and Transmission Association and its members and the initiation of a new partial-requirements contract.

May 18, 2022

2022 **Federal Energy Regulatory Commission**

Oral Testimony before the Federal Energy Regulatory Commission addressing just and reasonable Contract Termination Payments under the Wholesale Electric Service Contract between Tri-State Generation and Transmission Association and its members, several of which seek to green their power supply portfolios.

May 11-12, 2022

2022 **Federal Energy Regulatory Commission**

Deposition Testimony before the Federal Energy Regulatory Commission addressing just and reasonable Contract Termination Payments under the Wholesale Electric Service Contract between Tri-State Generation and Transmission Association and its members.

April 5, 2022

2022 **Federal Energy Regulatory Commission**

Rebuttal Testimony on behalf of United Power, Inc. before the Federal Energy Regulatory Commission, addressing just and reasonable Contract Termination Payments under the Wholesale Electric Service Contract between Tri-State Generation and Transmission Association and its members.

March 25, 2022

2022 **Federal Energy Regulatory Commission**

Oral Testimony before the Federal Energy Regulatory Commission addressing Order 888 unbundling and Mansfield and 7-factor tests for direct assignment of downstream delivery facilities.

March 18, 2022

2022 **NV Energy**
Gas Trading / Prudence

Direct Testimony before the Nevada Public Utilities Commission, on behalf of Nevada Power Company, examining whether the trades in its natural gas trading book were prudent.

March 1, 2022

2022 **NV Energy**
Gas Trading / Prudence

Direct Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, examining whether the trades in its natural gas trading book were prudent.

March 1, 2022

2022 **Confidential Client**

Affidavit before the London Court of Arbitration addressing industry and market conditions pertaining to a contract dispute.

February 17, 2022

2022 **PennEnergy Resources**

Oral Testimony on behalf of PennEnergy presenting a quantum of upstream oil and gas damages in American Arbitration Association (AAA) Case Number 012100025943.

February 17, 2022

2022 **Federal Energy Regulatory Commission**

Answering Testimony on behalf of United Power, Inc. before the Federal Energy Regulatory Commission, responding to a proposed mark-to-market approach to determine Contract Termination Payments under the Wholesale Electric Service Contract between Tri-State Generation and Transmission Association and its members.

February 4, 2022

2022 **Federal Energy Regulatory Commission**

Direct Testimony on behalf of United Power, Inc. before the Federal Energy Regulatory Commission, presenting a Balance Sheet Approach to determine Contract Termination Payments under the Wholesale Electric Service Contract between Tri-State Generation and Transmission Association and its members.

January 7, 2022

2021 **Confidential Electric Cooperative**

Deposition testimony before the International Institute for Conflict Prevention & Resolution regarding the valuation of a bespoke call option.

November 30, 2021

2021 **PennEnergy Resources**

Expert Report on behalf of PennEnergy presenting a quantum of upstream oil and gas damages in American Arbitration Association (AAA) Case Number 012100025943.

September 23, 2021

2021 **Federal Energy Regulatory Commission**

Affidavit on behalf of United Power, Inc. before the Federal Energy Regulatory Commission, presenting a Balance Sheet Approach to determine Contract Termination Payments under the Wholesale Electric Service Contract between Tri-State Generation and Transmission Association and its members.

September 22, 2021

2021 **Federal Energy Regulatory Commission**

Affidavit on behalf of United Power, Inc. before the Federal Energy Regulatory Commission, presenting analysis of the appropriate fee to be paid by United Power to terminate its wholesale supply contract with Tri-State Generation and Transmission Cooperative, Inc. and to liquidate its equity interest in Tri-State.

August 3, 2021

2021 **Public Service Commission of South Carolina**

Oral Testimony on behalf of Cherokee County Cogeneration Partners, LLC before the Public Service Commission of South Carolina, presenting analysis on avoided cost calculations and economic and policy goals of PURPA.

July 26, 29-30, 2021

2021 **Nova Scotia Utilities Review Board**

Oral Testimony on behalf of the Alternative Resource Energy Authority and the Berwick Electric Commission addressing policies toward the competitive power market and interaction with utility system planning and ratemaking, and particularly how those policies affected an investment in a wind farm.

June 17-18, 2021

2021 **Public Service Commission of South Carolina**

Rebuttal Testimony on behalf of Cherokee County Cogeneration Partners, LLC before the Public Service Commission of South Carolina addressing contracts with Qualifying Facilities under the Public Utility Regulatory Policies Act.

June 14, 2021

2021 **Nova Scotia Utilities Review Board, Canada**

Rebuttal Testimony on behalf of the Alternative Resource Energy Authority and the Berwick Electric Commission examining NSPI's application and the specific policies it proposes for the Backup and Top-Up ("BUTU") rate, and the implications for owners of a wind farm.

June 2, 2021

2021 **Federal Energy Regulatory Commission**

Direct Testimony on behalf of United Power, Inc. before the Federal Energy Regulatory Commission, outlining the ratemaking principles and policies that should govern the rates of Tri-State Generation & Transmission Association.

May 20, 2021

2021 **Public Service Commission of South Carolina**

Direct Testimony on behalf of Cherokee County Cogeneration Partners, LLC before the Public Service commission of South Carolina, presenting analysis on avoided cost calculations and economic and policy goals of PURPA.

May 3, 2021

2021 **Nova Scotia Municipal Utilities**
Backup/Top-Up Tariff Testimony

Expert witness in connection with the application of Nova Scotia Power Incorporated to amend its Wholesale Market Backup / Top-up Service Tariff and interactions with the municipal utilities' investment in a wind farm.

April 16, 2021

2021 **NV Energy**
Gas Trading / Prudence

Direct Testimony before the Nevada Public Utilities Commission, on behalf of Nevada Power Company, examining whether the trades in its natural gas trading book were prudent.

March 1, 2021

2021 **NV Energy**
Gas Trading / Prudence

Direct Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, examining whether the trades in its natural gas trading book were prudent.

March 1, 2021

2020 **Wisconsin Public Service Commission**
Return of Equity

Surrebuttal Testimony before the Wisconsin Public Service Commission on behalf of Verso Corporation and Verso Minnesota Wisconsin LLC addressing the fair return on equity for Consolidated Water Power Company.

October 26, 2020

2020 **Wisconsin Public Service Commission**
Return of Equity

Rebuttal Testimony before the Wisconsin Public Service Commission on behalf of Verso Corporation and Verso Minnesota Wisconsin LLC addressing the fair return on equity for Consolidated Water Power Company.

October 20, 2020

2020 **Wisconsin Public Service Commission**
Return of Equity

Direct Testimony before the Wisconsin Public Service Commission on behalf of Verso Corporation and Verso Minnesota Wisconsin LLC addressing the fair return on equity for Consolidated Water Power Company.

October 6, 2020

2020 **NV Energy**
Cost of Capital

Rebuttal Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, presenting analysis on the cost of capital.

September 18, 2020

2020	**North Carolina Utilities Commission** **Regulatory Policy** Oral Testimony before the North Carolina Utilities Commission, on behalf of Apple, Facebook and Google, presenting analysis on various regulatory matters. August 28, 2020
2020	**NV Energy** **Cost of Capital** Direct Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, presenting analysis on the cost of capital. June 1, 2020
2020	**NV Energy** **Cost of Gas / Prudence** Direct Testimony before the Nevada Public Utilities Commission, on behalf of Nevada Power Company, presenting analysis on whether its natural gas commodity trading was consistent with prudent utility practice. March 1, 2020
2020	**NV Energy** **Cost of Gas / Prudence** Direct Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, presenting analysis on whether NV Energy's natural gas commodity trading was consistent with prudent utility practice. March 1, 2020
2019	**Municipal Light & Power, Chugach Electric Association, Inc.** **Acquisition** Oral Testimony before the Regulatory Commission of Alaska on behalf of Chugach Electric Association, Inc., addressing the acquisition of Municipal Light & Power by Chugach Electric and post-acquisition tariff structures. November 5, 2019

2019 **Southwestern Electric Power Company**
Prudence of Investment in Power Generation Facilities

Sur-Surrebuttal testimony before the Arkansas Public Service Commission on behalf of Southwestern Electric Power Company addressing the prudence of certain investments in coal-fired power generation facilities.

October 2, 2019

2019 **Central Maine Power Company**
Marginal Cost Study

Oral Testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company in its 2018 Distribution Rate Case, addressing time-of-use pricing, marginal cost estimation and cost recovery for distribution network investment.

October 2, 2019

2019 **NV Energy**
Cost of Capital

Rebuttal Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, addressing the cost of capital for the Company's electric division.

September 19, 2019

2019 **Municipal Light & Power, Chugach Electric Association, Inc.**
Acquisition

Oral Testimony before the Regulatory Commission of Alaska on behalf of Chugach Electric Association, Inc., addressing the acquisition of Municipal Light & Power by Chugach Electric, including the structure of a renewables PPA.

September 5-6, 2019

2019 **Corporate Commission of Arizona**

Oral Testimony on behalf of Grand Canyon State Electric Cooperative Association, Inc. before the Corporate Commission of Arizona towards contracts with Qualifying Facilities.

August 27, 2019

2019 **Central Maine Power Company**
Cost Study for Electric Distributor

Surrebuttal Testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company in its 2018

Distribution Rate Case, addressing the theory of electric utility costing and the implementation of a cost study for the distribution network.

August 22, 2019

2019 **Municipality of Anchorage (ML&P) & Chugach Electric Association**
Reasonableness of Proposed Merger

Reply Testimony Before the Regulatory Commission of Alaska addressing the acquisition of Municipal Light & Power by Chugach Electric.

August 2, 2019

2019 **Chugach Electric Associate Inc.**
Cost of Capital

Oral Testimony Before the Regulatory Commission of Alaska addressing the cost of capital for Chugach Electric.

July 15, 2019

2019 **NV Energy**
Cost of Capital

Direct Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, addressing the cost of capital for the Company's electric division.

June 3, 2019

2019 **Avangrid NY**
Marginal Cost Study

Direct Testimony before the New York State Public Service Commission on behalf of New York State Electric & Gas Corporation, providing marginal cost estimates for purposes of informing reasonable electric and gas distribution rates.

May 20, 2019

2019 **Avangrid NY**
Marginal Cost Study

Direct Testimony before the New York State Public Service Commission on behalf of Rochester Gas & Electric Corporation, providing marginal cost estimates for purposes of informing reasonable electric and gas distribution rates.

May 20, 2019

2019	**Central Maine Power Company Marginal Cost Study** Rebuttal Testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company in its 2018 Distribution Rate Case, addressing time-of-use pricing, marginal cost estimation and cost recovery for distribution network investment. April 25, 2019
2019	**Municipality of Anchorage (ML&P), Chugach Electric Association Reasonableness of Proposed Merger** Pre-filed direct testimony on behalf of Chugach Electric Association, Inc. before the Regulatory Commission of Alaska supporting Chugach's proposed acquisition of ML&P from the Municipality of Anchorage. Testimony addresses the valuation of ML&P, the reasonableness of the purchase price, forecast synergy savings, market pricing for a renewables Power Purchase Agreement, and the tangible benefits that will accrue to ratepayers as a result of the merger. April 1, 2019
2019	**Public Service Company of New Mexico Reasonableness of Power Purchase Agreement** Affidavit before the Federal Energy Regulatory Commission including a benchmarking analysis of a solar power purchase agreement under FERC's *Edgar* and *Ocean States* standards. March 15, 2019
2019	**NV Energy Cost of Gas / Prudence** Direct Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, addressing the reasonableness of the Company's natural gas trading. March 1, 2019
2019	**Southwestern Electric Power Company Prudence of Investment in Power Generation Facilities** Direct Testimony before the Arkansas Public Service Commission on behalf of Southwestern Electric Power Company addressing the prudence of the company's investments in the Dolet Hills Power Plant. February 28, 2019

CONSULTING EXPERT EXPERIENCE

2022 — **Confidential Client**
Litigation

Valuation of wind power supply agreement, green certificates, and replacement power to support mediation.

2022 — **Confidential Client**
Advisory

Estimate the value of contracting with a new wind farm taking into account the value of green certificates, energy, ancillary services, and capacity.

2022 — **Confidential Client**
Advisory

Estimate the value of contracting with a new solar array taking into account the value of green certificates, energy, ancillary services, and capacity.

2022 — **Confidential Client**
Advisory

Estimate the value of the new battery addition to the system, both from the client's perspective given the trading rules and from the perspective of the TSO.

2022-Present — **Confidential Client**
Exit from Generation & Transmission Cooperative

Expert on appropriate buyout payment for a member to leave its transmission and generation cooperative and enter into new green power supply contracts.

2020-Present — **Confidential Client**
Exit from Generation & Transmission Cooperative

Expert on appropriate buyout payment for a member to leave its transmission and generation cooperative and enter into new power supply contracts.

2019-Present — **United Power**
Exit from Generation & Transmission Cooperative

Expert on appropriate buyout payment for United Power to leave the Tri-State Transmission and Generation Cooperative.

2019-2020 **Confidential Client**
Decommissioning of Coal-Fired Power Plant

Expert addressing the net cost of decommissioning a coal-fired power plant and regulatory cost recovery mechanisms.

2019 **Confidential Client**
Oil Products Pipeline – Competitive and Regulatory Analysis

Expert in dispute related to a FERC-regulated oil products pipeline, focusing on competitive and financial analysis.

2019 **Confidential Client**
Financial Structure Analysis

Expert in dispute related to the financial structure of assets owned by a midstream oil and products company.

2016 **Confidential Client**
Valuation of Solar Generation Facilities

Expert in dispute related to the valuation of solar facilities. Provided valuation options to counsel to evaluate the reasonableness of the claimed tax basis and Section 1603 cash grant.

2014 **GazProm**
Dispute Over Value of Gas Fields

Expert in dispute related to the value of development and production of gas in Russia for export to the US and re-gasification via an import facility in Corpus Christi, TX.

2014 **Confidential Client**
Offshore Exploration and Production Permit Arbitration

Expert in dispute related to an agreement between two firms to develop an offshore gas field in New Zealand in arbitration at the ICC International Court of Arbitration.

2014 **Confidential Client**
Breach of Contract Damages Valuation for Gas Supply Agreement

Valued damages in a breach-of-contract dispute regarding gas supply in Western Australia.

2013–2016 **Gaz Métro**
Cost Recovery of Gas Distribution System Upgrade

Advised client on regulatory merits of ratemaking for distribution system upgrade. Performed survey of ratemaking policies for similar upgrades in other jurisdictions in connection with a proceeding before Provincial regulator.

2014-2015 **Confidential Client**
Gas Supply Agreement Negotiation

Advise on cost of service and LNG contract price issues in Western Australia.

2014- 2015 **Alliance Pipeline**
Restructuring of Services and Tolls

Advised on Alliance's restructuring proposal in a matter before the National Energy Board. Supervised modeling of pipeline tolls and assessment of natural gas pipeline market power.

2014-2015 **Gazprom OAO**
Civil Dispute Involving Gas Field Development and LNG importation

Supervised modelling of LNG netback prices and damage calculations in preparation for a jury trial before a Tarrant County, Texas District Court. Consulted with respect to a dispute between a U.S oil company and Russian oil company regarding ownership of a Russian gas field, tortious interference, and trade secret misappropriation with regards to a plan to import LNG into the United States in the mid-2000s.

2014 **FortisBC Energy Inc.**
Tolling for Pipeline in Canada

Analyzed toll methodology and advised on regulatory issues related to a tolling proposal of NGTL's North Montney Mainline, an extension of the existing NGTL Alberta System.

2014 **Royal Bank of Canada**
Gas Supply Agreement Dispute

Served as consulting expert in a gas supply agreement dispute between RBC and three municipal gas distributors in Nevada and Iowa. Case involved analysis of Basel III regulations, capital requirements, commodity swaps and interest rate swaps.

2013	**Confidential Client** **Valuation and Pricing Analysis** Performed valuation and pricing analysis for oil pipeline dispute in Texas. Provided advice to outside counsel throughout litigation.
2012-2014	**ATCO Gas & ATCO Electric** **Cost of Service / Capital Trackers** Provided expert review of ATCO Gas and ATCO Electric's capital tracker proposals, including a survey of capital trackers in other jurisdictions.
2012–2013	**Confidential Client** **Valuation of Oil Pipeline Company and its Hedging Positions** Performed valuation of oil pipeline company and its hedging positions in litigation involving an alleged breach of fiduciary duty. Provided advice to outside counsel throughout litigation.
2012–2013	**Confidential Client** **Approaches to Regulatory Accounting and Cost-of-Service Regulation** Contributed to study assessing benefits of various approaches to regulatory accounting and cost-of-service regulation for pipelines.
2011–2013	**Confidential Client** **Possible Outcomes of Power Contract (PPA) Disputes** Analyzed potential litigation and settlement outcomes in a series of power contract disputes. Provided advice to outside counsel.
2011–2012	**Confidential Client** **Oil Pipeline Cost of Service and Depreciation Policies** Advised counsel to a shipper in an intrastate oil pipeline company rate case before the Kansas Corporation Commission.
2011	**Coffeyville Resources Refining & Marketing, LLC** Upstream and midstream pricing issues. Advised the Coffeyville refinery on the terms and conditions of midstream services to facilitate receipt of upstream supply.

2011 **Confidential Client**
Antitrust Aspects of a Proposed Pipeline Merger

Analyzed antitrust aspects of oil pipeline combinations in connection with a proposed merger. Provided advise to outside counsel.

2010–2011 **Confidential Client**
Valuation of Generation Assets

Performed valuation of renewables power plant in context of alleged expropriation in international arbitration (investor-state dispute).

2010 **Hydro Québec, Canada**
Grid Connection and Upgrade Cost Policy

Analyzed grid connection and upgrade cost policy. Evaluated existing policy to allocate costs of grid upgrades to generation developers and system users. Suggested modifications to policy accounting for renewables expansion. Prepared benchmarking analysis comparing the company's practices to those of over a dozen other entities in North America.

2008 **Confidential Client**
Allegations of Energy Market Manipulation

Advised on the evaluation of allegations of energy market manipulation in the context of electricity trading in RTO-managed markets.

2007 **Confidential Client**
Valuation of Long-Dated Oil Warrants

Performed valuation of long-dated oil warrants priced off Venezuelan crude oil in context of damages calculation.

2006 **Confidential Client**
Damages Valuation in Securities Class Action

Valued damages in a securities class action related to the bankruptcy of an energy retailer.

2003-2004 **Confidential Client**
Bid Process Advantages: Generation Pricing and Transmission Costs

Contributed to testimony on behalf of a large electric utility regarding an affiliate transaction that resulted from a competitive solicitation. Testimony before FERC focused on whether the affiliate was advantaged during the bid process, both with respect to generation pricing and electric transmission cost.

2003

Confidential Client
Valuation, Economic, Accounting, and Hedging analysis

Performed valuation, economic, accounting, and hedging analysis of a gas-fired power plant in an international arbitration matter.

2002

Confidential Client
Prudence of Forward Power Purchases

Contributed to testimony on behalf of an electric utility regarding the prudence of forward power purchases during the Western power crisis.

2002–2003

Pacific Gas & Electric
Valuation of Damages Due to Gas Pipeline Capacity Withholding

Performed analyses of damages from withheld pipeline capacity into California. Analyses led to $1 billion settlement.

2002–2003

Confidential Client
Prudence of Forward Power Purchases

Contributed to testimony regarding the prudence of Department of Water Resources's forward power purchases during the Western power crisis.

2002

Confidential Client
Electric and Gas Hedging Strategies for its Generation Assets

Contributed to testimony on behalf of an energy marketing and trading firm regarding electric and gas financial hedging strategies for its generation assets, including an examination of the nature of competition among energy marketing and trading firms and strategies.

2001–2002

Pacific Gas & Electric Company
FERC Refund and Other Related Proceedings

Analysis and support to a California utility in the context of the FERC refund and other related proceedings, 2001-2002.

2001–2002

Pacific Gas & Electric Company
Value of a Long-Term Affiliate Power Sales Agreement

Contributed to testimony before FERC relating to the value of a long-term affiliate power sales agreement. Involved analysis and valuation of over 100 long-term power contracts (PPAs) in the context of this benchmarking analysis.

2001 **Confidential Client**
Valuation of a Passive Equity Interest

Contributed to testimony on behalf of a leading US energy company regarding the valuation of a passive equity interest in an IPP project in El Salvador.

2001 **Baltimore Gas & Electric Company**
Business Separation of Constellation Energy Group

Contributed to testimony submitted to the Public Service Commission of Maryland on the business separation of Constellation Energy Group.

1998 **Baltimore Gas & Electric Company**
Valuation of Generation Assets

Performed valuation of Baltimore Gas & Electric Company's hydro, nuclear, coal and gas-fired generation assets in the context of stranded cost calculations during restructuring, 1998.

1995–1996 **Confidential Client**
Analysis of Market Concentration

Performed HHI analyses to support testimony presenting a competitive assessment of the Western electric generation market in the US, 1995-1996.

1994–1995 **Confidential Client**
Damages Valuation in Securities Class Action

Estimated losses and alleged damages for several mutual funds that invested in derivative securities.

1994–1995 **Confidential Client**
Damages Valuation in Securities Class Action

Estimated losses and alleged damages for several mutual funds that invested in derivative securities.

1994 **Goldman Sachs**
Default Risk Studies on Fixed-Income Instruments

Prepared default risk studies on fixed income instruments for counsel to Goldman Sachs in a broker/dealer arbitration.

1994 **Confidential Client**
Damages Valuation in Securities Class Action

Consulted to counsel for an infomercial company on materiality, liability, and damages in a shareholder class action suit.

1993 **Confidential Client**
Damages Valuation in Securities Class Action

Assessed materiality and damages in a 10b-5 class action against a major pharmaceutical company.

ADVISORY PROJECTS

2022 **Offshore Wind Auction**
Due Diligence for Bidder

Provided strategic advice relating to an upcoming offshore wind auction in Europe.

2021 **Offshore Wind Auction**
Due Diligence for Bidder

Provided strategic advice and due diligence to European developers relating to the competitive landscape for an upcoming offshore wind auction.

2020 **Offshore Wind Auction**
Due Diligence for Bidder

Provided strategic advice and due diligence relating to the competitive landscape for past and upcoming offshore wind auctions.

2020 **Acquisition of Gas LDC**
Due Diligence for Investor Group

Provided strategic advice and due diligence relating to the financial valuation of a gas LDC and prospective acquisition.

2017-2019 **Valuation of Vertically-Integrated Electric Utility**
Due Diligence for Prospective Acquirer

Retained by an electric utility to advise on valuation of a target utility acquisition. Assisted client in developing reasonable offers to acquire the target electric utility. Advised utility during negotiations.

2017 **Investment in Coal-Fired Power Plant**
Due Diligence for Owner

Retained by a confidential owner. Provided strategic advice and due diligence relating to the financial valuation of owners interest and prospective sale.

2017 **Marginal Cost Study for Value of Distributed Renewable Resource**
Due Diligence for Prospective Acquirer

Retained by NYSEG and RG&E to perform a marginal cost study to estimate key components of the value stack, to be paid to solar, wind, and other distributed energy resources,

2017 | **Leveraged Lease tied to Coal-Fired Power Plant**
Due Diligence for Prospective Acquirer

Retained by a confidential acquirer to evaluate a target utility-related investment. Provided strategic advice and due diligence relating to the financial valuation and post-acquisition benefits.

2016 | **Upstream Oil and Gas Acquisition**
Due Diligence for Prospective Acquirer

Retained by a confidential client to evaluate a prospective investment in an upstream oil and gas field. Advised the client on key elements of the valuation.

2016 | **Utility Merger**
Due Diligence on Merger Benefits

Retained by a confidential acquirer to evaluate merger benefits in the context of the combination of two adjacent electric utilities. Provided strategic advice and due diligence relating to merger benefits.

2016 | **Wind Power Transaction**
Due Diligence for Prospective PPA Offtaker

Retained by a confidential offtaker to evaluate the costs, benefits and risks associated with a prospective long-term power purchase transaction backed by a wind farm.

2016 | **Electric Utility Acquisition**
Due Diligence for Prospective Acquirer

Retained by a confidential equity investor to evaluate key inputs for the acquirer's valuation model of an electric utility. Advised investor on key elements of the valuation.

2015 | **Ministry of Energy, Mexico**
Restructuring of the Mexican power and gas sectors

Served as leader for several work streams performed on behalf of the Mexican Ministry of Energy implementing energy sector restructuring. Advice included the design of a competitive spot market, the development of green power auctions (solar and wind), basic service supply pricing, electricity transmission pricing, upstream gas pricing, pipeline rates and the development of a regulatory framework for the sector.

2015 **Southern Star Central Gas Pipeline**
Due Diligence for Prospective Acquirer

Retained by a confidential equity investor to evaluate regulatory and investment risk associated with the prospective acquisition of an interest in Southern Star. Analyzed likely outcomes in the pipeline's upcoming rate case, and their implications for the valuation of the target.

2015 **Independent Electricity System Operator (IESO)**
Reasonableness of 6,300 MW Power Transaction

Retained by IESO in Ontario, Canada, to prepare, together with a team of NERA experts, an Opinion as to the Fairness of the Amended and Restated Bruce Power Refurbishment Implementation Agreement.

2015 **ESKOM, South Africa**
Regulatory Strategy for Cost Recovery

Retained by ESKOM to advise on regulatory strategy, treatment of coal-plant operation and associated fuel costs, delays in unit online dates, prudent utility practice, and other regulatory issues.

2015 **Bermuda Electric, Bermuda**
Regulatory Strategy, Cost of Service, and Tariffs

Advised on regulatory strategy. Developed costing and pricing model for Bermuda Electric.

2014 **Hawaiian Electric Company**
Fuel Adjustment Clause and Oil Hedging

Retained by Hawaiian Electric Company to provide analysis regarding the efficiency incentives embedded in the company's fuel adjustment clause (ECAC). Analyzed the possibility of hedging oil price volatility through commercially-available contracts.

2014 **Confidential Client**
Pricing Principles for Domestic Gas Reservation Policy

Formulated a methodology to determine a schedule of reasonable prices using a cost of service approach for gas that the company is obligated to market under the domestic gas supply policy in Western Australia.

2012/2013 **Atlantic Path 15**
Due Diligence Study for Confidential Potential Buyer

Performed regulatory due diligence in connection with the potential acquisition of Atlantic Path 15 transmission assets. Evaluated the regulatory climate at FERC and analyzed FERC decisions from prior rate cases, with a focus on allowed rate of return. Used NERA rate-of-return models to replicate the FERC methodology and to predict the rate-of-return to be allowed by FERC in the next rate case.

2013 **Energy Trading Entity**
Price Risks and Electricity Transmission Development

Retained by energy trading entity to perform an independent study of price risks and electricity transmission development in the ERCOT market.

2013 **Electric Industry Client**
Reactive Power Compensation

Retained by electric industry client to analyze electricity transmission tariffs and reactive power compensation in competitive electric markets.

2012/2013 **New Mexico Natural Gas Company**
Due Diligence Study for Confidential Acquirer

Performed regulatory due diligence in connection with the potential acquisition of New Mexico Natural Gas. Assessed hurdles to getting the transaction approved by regulatory authorities. Analyzed recent rate actions by the state commission and the likely outcomes of future cases. Advised on key inputs into the acquirer's financial model.

2012 **Oil Industry Client**
Regulation Benchmarking in Downstream Oil Sector

Retained by oil industry client to advise on margins and to perform an international benchmarking of the regulation of the downstream oil sector.

2012 **Hawaiian Electric Company**
Hedging and Rate Stabilization

Retained by Hawaiian Electric Company to provide analysis regarding hedging of fuel oil and diesel fuel purchases in order to stabilize customer rates.

2011 **Confidential Client**
Implications of CFTC Proposed Definition of Swap Dealer

Advised on margin, capital and reporting implications of CFTC proposed definition of swap dealer under Dodd Frank.

2010 **Confidential Client**
Leveraged Lease Transaction

Provided litigation support services with respect to a dispute over a leveraged lease transaction.

2010 **Confidential Client**
Valuation, Risk Assessment and Analysis of Offtake Contract Options

Performed detailed valuation, risk assessment and analysis of offtake contract options for a hydroelectric power plant.

2009 **Potomac Edison Company**
Capital Investment Planning

Performed least-cost capital investment planning on behalf of the Potomac Edison Company.

2009 **Government of New Brunswick, Canada**
Advised on Electric Utility Valuation

Advised Government of New Brunswick on the valuation of the vertically-integrated, provincially-owned electric utility, NB Power, in connection with the potential sale to Hydro Québec. Developed a financial and rate model reflecting the New Brunswick regulatory system and performed valuations for a stand-alone and merged case and performed numerous valuations of the benefits to the acquirer. Developed key inputs for the valuation, including the Point Lepreau Nuclear Generation Station. Coordinated development of fairness opinion.

2009 **Energy East**
Cost of Capital

Advised on rate-of-return issues for electricity distributors in New York State.

2008 **Confidential Client**
Contract Design

Advised on design of structured contract for new renewable power plant, new electricity transmission lines and associated RFPs.

2008 **Commission for Energy Regulation**
Review of SOLR Tariffs

Advise the Commission for Energy Regulation on the review of SOLR tariffs in the Republic of Ireland.

2008 — **Comisión Nacional de Energía**
Market Mechanisms for Distributions to Serve Default Customers

Advised on design and implementation of market mechanisms by which Spanish electric utilities buy energy to serve default customers.

2006–2009 — **Hawaiian Electric Company**
Hedging Options for Fuel

Performed economic and accounting analysis of hedging options for low sulfur fuel oil, diesel and fuel oil on behalf of Hawaiian Electric Company.

2004–2010 — **Commonwealth Edison and Ameren's Illinois Utilities Power Auction**
Competitive Procurement for Power Supply

Advised Commonwealth Edison and Ameren's Illinois utilities on the design of a competitive procurement for short- and long-term power supply, including the contractual framework for energy purchases, 2004 to 2010.

2004–2012 — **New Jersey and Maryland Distribution Utilities Power Auction**
Mark-to-Market Issues and Credit Policies

Advised several utilities in the Eastern Interconnection on mark-to-market issues and credit policies.

1999–2008 — **New Jersey Distribution Utilities Power Auction**
Contract Design and Implementation

Worked with credit representatives of New Jersey distribution utilities on contract design and implementation of the contract credit terms. Coordinated the utilities' responses to changes to the forms of letters of credit proposed by bidders; oversaw bidder credit qualification process; managed approval process for alternate guaranty instruments, and served as advisor to utilities when contract interpretation issues arose, 1999 to 2008.

1999–2008 — **FirstEnergy Companies Power Auction**
Competitive Procurement of Power Supply

Advised the FirstEnergy Companies on the design of a competitive procurement for intermediate term power supply, including the contractual framework for energy purchases, 2004-2005.

2003 — **Commission for Energy Regulation Power Auction**
Hedging Agreement and a Power Plant Construction Agreement

Advised the Commission for Energy Regulation in Ireland on the structure of a long-term hedging agreement and a power plant construction agreement; assisted with the development of the hedging contract and the tender documentation; performed bid evaluation.

2002 **Sierra Pacific Resources**
Risk Management Strategies

Advised a major west coast utility in the US on the development of its risk management policy and procedures; reviewed past trading and risk management strategies; and performed an assessment of its risk measurement and reporting techniques, including credit risk management policy.

2000 **Ministry of Energy, México**
Mexican IPP Solicitation Program

Advised on the development of the Mexican IPP solicitation program, including transaction structure (IPP v. BLT v. BOT), credit risk management, model contracts, and bid evaluation (the Comisión Federal de Electricidad has procured as much as 2000 MW per year of long-term power supply from IPPs).

2000 **Comisión Federal de Electricidad, Mexico**
Credit and Collateral Requirements for a Power Purchase Agreement

Advised the Comisión Federal de Electricidad in Mexico on credit and collateral requirements for an-asset backed power purchase agreement with an IPP based in Mexico, including advice on the development of comparable credit and collateral requirements for an import transaction that was to be made on a firm basis with liquidated damages.

1998–2000 **Ministry of Energy, Mexico**
Restructuring and Privatization of the Mexican Electricity Sector

Consulted to the Mexican Ministry of Energy on the restructuring and privatization of the Mexican electricity sector, the design of a competitive spot market, and the policy of IPP solicitations, electricity transmission pricing, upstream gas pricing and the development of a regulatory framework for the sector.

1998–1999 **Ministry of Energy, Mexico**
Assessing Competition in Restructured Mexican Electric Generation

Contributed to study assessing competition in restructured electric generation market in Mexico.

1999	**Swiss Re** **Novel Insurance Packages to Hedge Electric Price and Operations Risk** Assisted Swiss Re in the development of the modeling for the creation of novel insurance packages to hedge electric price and operations risk, 1999.
1998	**Iberdrola S.A., Spain** **Seminars on the Deregulated Markets for Gas and Electricity in the US** Designed and conducted a series of three training courses for representatives of Iberdrola S.A. (Spain's principal private utility), which consisted of seminars on the deregulated markets for gas and electricity in the US, followed by a series of interviews with large utilities, IPPs, and energy marketers. Courses were designed to provide the European traders with an understanding of best practices employed by energy traders in the US, with respect to risk management (credit, market, and operational), 1998.
1998	**C.E.L.P.E, Brazil** **Risk Management and Energy Trading** Assisted in training senior management of Iberdrola's Brazilian subsidiary C.E.L.P.E. in the area of risk management and energy trading.
1998–2000	**Baltimore Gas & Electric Company** **Sector Restructuring** Consultant to Baltimore Gas & Electric Company on sector restructuring.
1998–1999	**Baltimore Gas & Electric Company** **Valuation of Electric Power Assets** Assisted in developing market value estimates of Baltimore Gas & Electric Company's generation fleet, including Calvert Cliffs Nuclear Power Plant.
1998	**Confidential Client** **Generation and Fuel Strategy** Participated in the development of a generation and fuel strategy for a large merchant generator and energy trader.
1996	**Iberdrola, S.A, Spain** **Restructuring of the Electricity Sector** Consultant to Iberdrola, S.A. on issues relating to the restructuring of the electricity sector in Spain.

1996 **Confidential Client**
Investment Strategy

Consultant to a major southeastern electric utility on investment strategy in the US including valuation of various targets.

1996 **Confidential Client**
Competitive Analysis of Electric Generation

Performed competitive analysis of electric generation market for utilities in eastern US.

1996 **New York State Electric and Gas Company**
Restructuring of the Electricity Market in New York State

Consultant to the New York State Electric and Gas Company on issues relating to the restructuring of the electricity market in New York State.

1995–1996 **New York Power Authority**
Sector Restructuring

Consultant to senior management of the New York Power Authority on issues relating to the New York Competitive Opportunities Docket.

1995 **Southern California Edison Company**
Proposed Restructuring of California's Electric Services Industry

Consultant to Southern California Edison Company on issues relating to the California Public Utilities Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.

Publications and Presentations

2023 **The Electricity Journal**

Will Allowed Returns for Regulated Utilities Keep Up With Inflation? Forthcoming.

April 2023

2022 **Global Arbitration Review**

Damages: geopolitics increases caseloads and complicates quantum.

December 2022

2019 **Republic of Indonesia**

Presentations to Perusahaan Gas Negara, BHP Migas (regulator), and the Ministry of Energy and Mineral Resources of the Republic of Indonesia addressing the design and solicitation of natural gas distribution concessions.

October, 2019

2019 **Republic of Indonesia**

Presentations to Perusahaan Gas Negara and BHP Migas (regulator) addressing connection policies and market development strategies for greenfield natural gas distributors.

October, 2019

2019 **Florence School of Regulation**
Specialised Training on the Regulation of Gas Markets

Gas Sector Regulation: The US Experience

March 2019

2019 **Electricity Journal**

Could Mexico's Capacity Market Design Lead to Gaming by Generators?

March 2019

2018 **Perusahaan Gas Negara**
Specialized Training

Conducted specialized training course on the design and award of energy-sector concessions.

December 2018

2018 **Center for Research in Regulated Industries**
Eastern Conference

Mexican Capacity Market Design and Market Power Potential.

June 2018

2018 **Florence School of Regulation**
Specialised Training on the Regulation of Gas Markets

Gas Sector Regulation: The US Experience.

March 2018

2017 — **Electricity Journal**

Beyond net metering: A model for pricing services provided by and to distributed generation owners, such as rooftop solar.

April 2017

2017 — **Law Seminars International Electric Utility Rate Case Conference**

Beyond Net Metering: Ratemaking Challenges from Distributed Generation (Las Vegas).

March 16, 2017

2017 — **Public Utilities Fortnightly**

Interest Rates After the Election: What They Mean for Public Utility Returns.

January 2017

2016 — **Perusahaan Gas Negara**

Provided in-depth training on regulatory practice and tariff design for gas pipelines and distribution companies (Jakarta).

December 2016

2016 — **Electricity Journal**

Low interest rates and unprecedented stock market volatility: What they mean for your next rate case.

January-February 2016

2016 — **An Economic Analysis of the Acquisition of ConocoPhillips' Interest in the Beluga River Unit**

A Report Prepared for Chugach Electric Association, Inc. and Anchorage Municipal Light and Power.

March 11, 2016

2016 — **Law Seminars International, 12th Annual National Conference on Current Issues in Electric Utility Ratemaking**

Policy Options to Address Cross Subsidies from Self Generation.

March 14, 2016

2016	**International Arbitration Group of International Law Firm** Applications of Economic Analysis in International Arbitration (with a focus on the Energy Sector), New York. January 12, 2016
2015	**The Electricity Journal** Low interest rates and unprecedented stock market volatility: What they mean for your next rate case. December 2015
2015	**Utility Regulation Conference: Rate Case, ROE, and Reliability** Brave New World for Return on Equity (Washington DC). December 10-11, 2015
2015	**Law Seminars International, Energy in the Northeast** Energy Sector Developments and the Cost of Capital (Boston). September 29, 2015
2015	**Law Seminars International, Rate Case Conference** A Brave New World for Return on Equity (Las Vegas). March 5, 2014
2014	**Law Seminars International, Rate Case Conference** Current Challenges in Determining Appropriate Rates of Return for Public Utilities (Las Vegas). February 28, 2014
2014	**National Energy Agency (China) and Representatives of the State Grid** Regulatory Accounting and the FERC Uniform System of Accounts (Beijing). January 16, 2014

2012	**Agencia Nacional de Petroleo, Gas Natural e Combustiveis (Brazil)** Training Course on Natural Gas Pipeline Regulation in the United States (Rio de Janeiro). September 18-19, 2012
2012	**Center for Research in Regulated Industries Eastern Conference** Optimal Capital Structures for Regulated Public Utilities: When Does an Imputed Debt Ratio Make Sense for Ratemaking Purposes? Eastern Conference (Delaware). May 18, 2012
2012	**Energy Policy Briefing Note** The Real Costs of Eliminating Unsecured Credit Lines and Requiring Cash Collateral in OTC Swaps Markets. Co-Author: Sharon Brown-Hruska March 13, 2012
2012	**Law Seminars International, Electric Utility Rate Case Conference** Marginal Cost Pricing for Rate Design (Las Vegas). February 2, 2012
2012	**Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition** Gas Pipeline Overearning Investigations (Newark) January 13, 2012
2011	**Working Group of Commercial Energy Firms** Cost-Benefit Analysis of the CFTC's Proposed Swap Dealer Definition. December 20, 2011
2011	**Law Seminars International, Renewable Energy in the Pacific Northwest** Abundant Low-Cost Natural Gas? A Driver of Market Activity. August 4, 2011

2011 **Public Utilities Fortnightly**

Zone of Reasonableness: Coping with Rising Profitability a Decade after Restructuring.

July 2011

2011 **Law Seminars International, Electric Utility Rate Case Conference**

Rate Design Issues Among Customer Classes (Las Vegas)

February 10, 2011

2011 **Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries**

Decoupling and the Cost of Equity (Newark)

January 14, 2011.

2010 **New York State Bar Association, Business Law Section Committee on Public Utility Law**

Getting Renewables to Market: The Importance of Transmission Ratemaking Policy (New York)

July 24, 2010

2009 **Law Seminars International Conference, Renewable Energy in New England**

Getting Renewable Power to Market (Boston)

June 25, 2009

2008 **Report for Baltimore Gas & Electric and Allegheny Power**

Evaluation of Longer-Term Procurement Plans

October 1, 2008

2008 **Electricity Journal**

The Continuing Rationale for Full and Timely Recovery of Fuel Price Levels in Fuel Adjustment Clauses

July 2008

2008 **Energy in the Southwest Conference**

Natural Gas as a Fuel: Will There Be Enough? At What Prices?

July 22, 2008

2007 **NERA Economic Consulting**

The Line in the Sand: The Shifting Boundary Between Markets and Regulation in Network Industries.
Coauthor.

2007 **Electric Utility and Natural Gas Interdependency**

Managing Risk in Interdependent Gas and Power Markets (Houston)

March 6, 2007

2004 **Electricity Journal**

FERC Imposes New Constraints on Utility Procurement

October 2004

2003 **Northeast Gas Storage and Supply Strategies**

Can Your Capital Structure Handle Today's Market, Credit and Liquidity Risks? (Boston)
June 17, 2003

1996 **World Bank**

Regulatory and institutional reforms in the Chinese power sector
Contributor

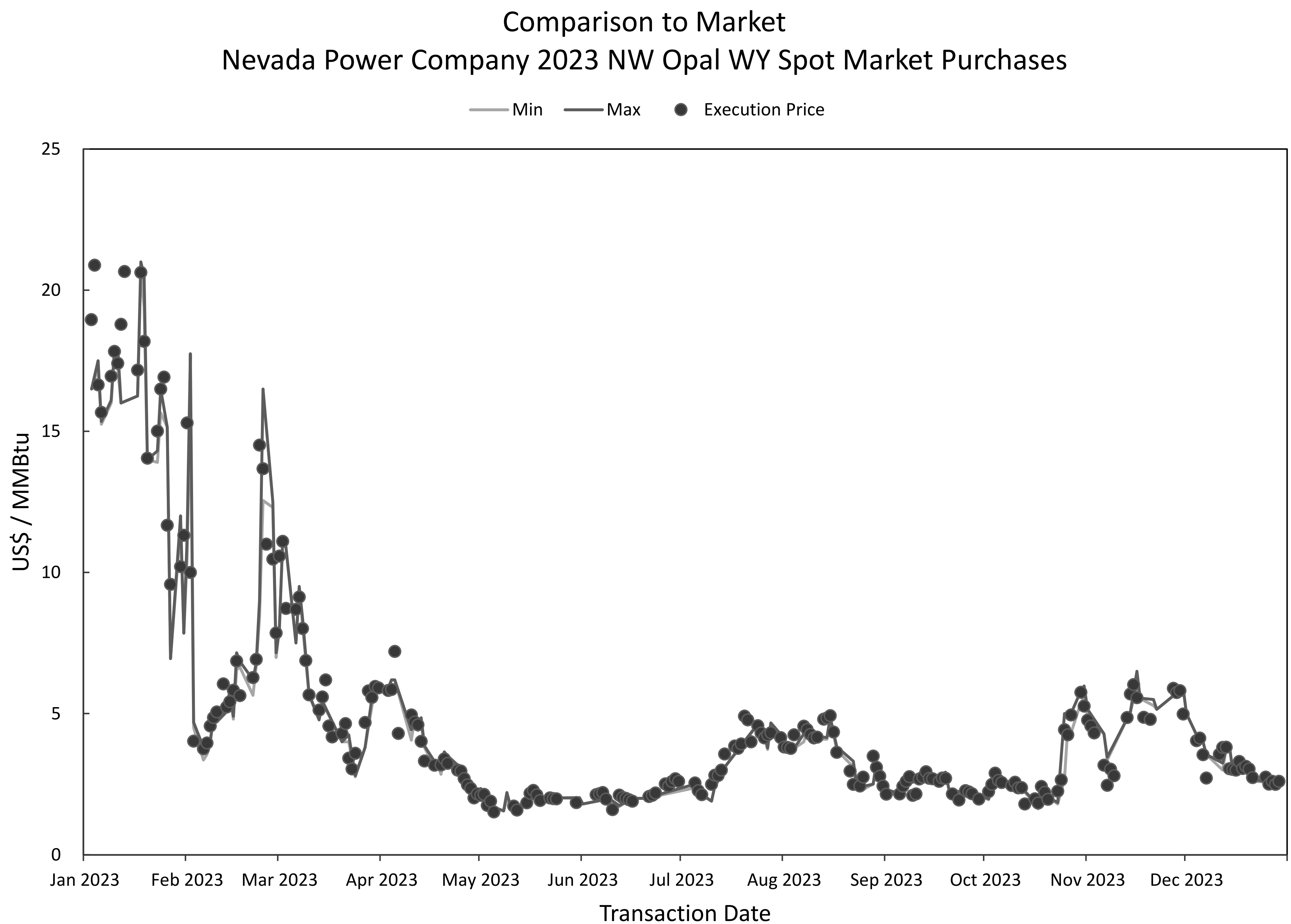
1996

1993 **World Development**

Political Economy, Convergence and Growth in Less Developed Countries
Coauthor

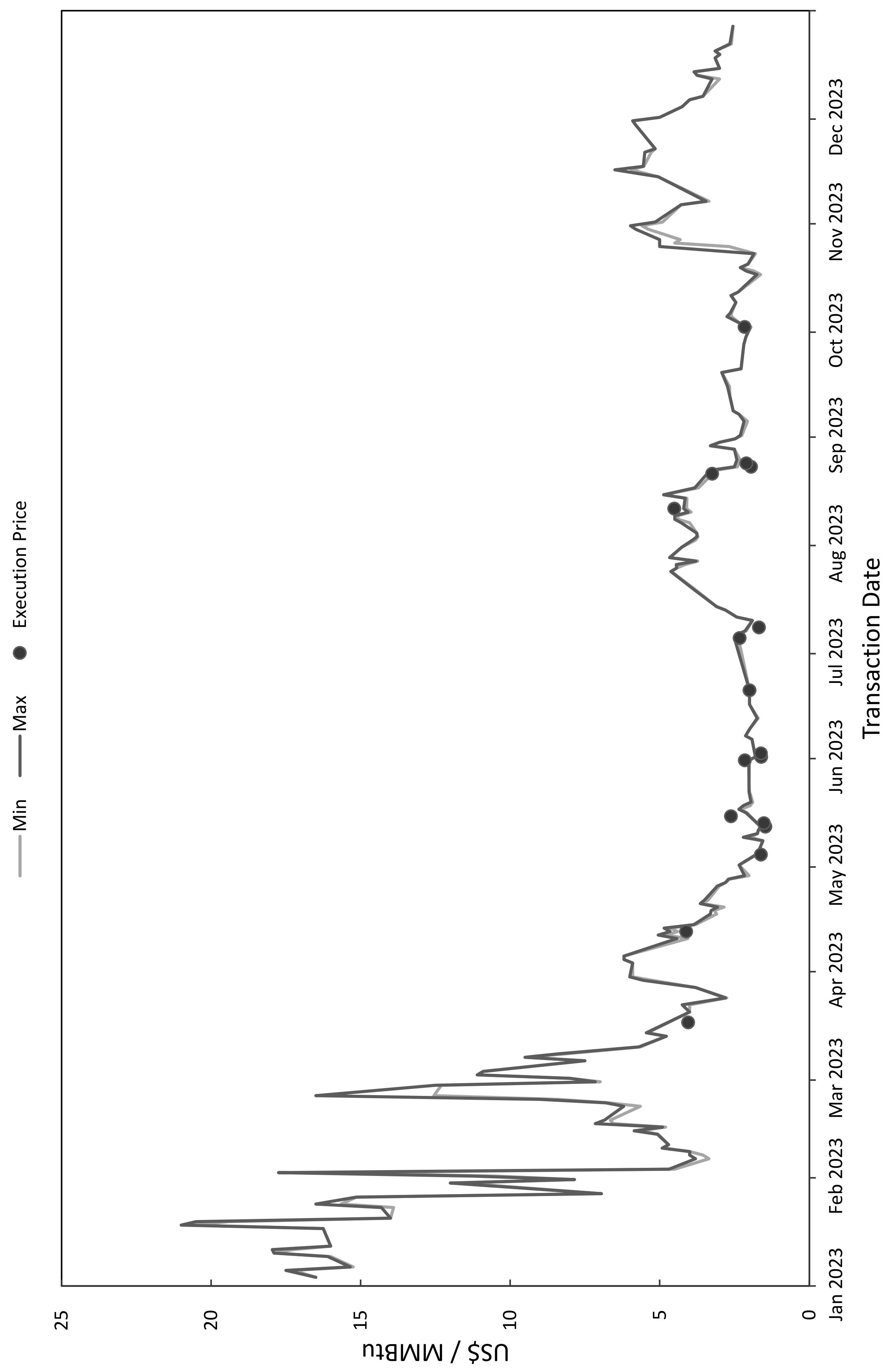
1993

EXHIBIT STRUNK-DIRECT-2



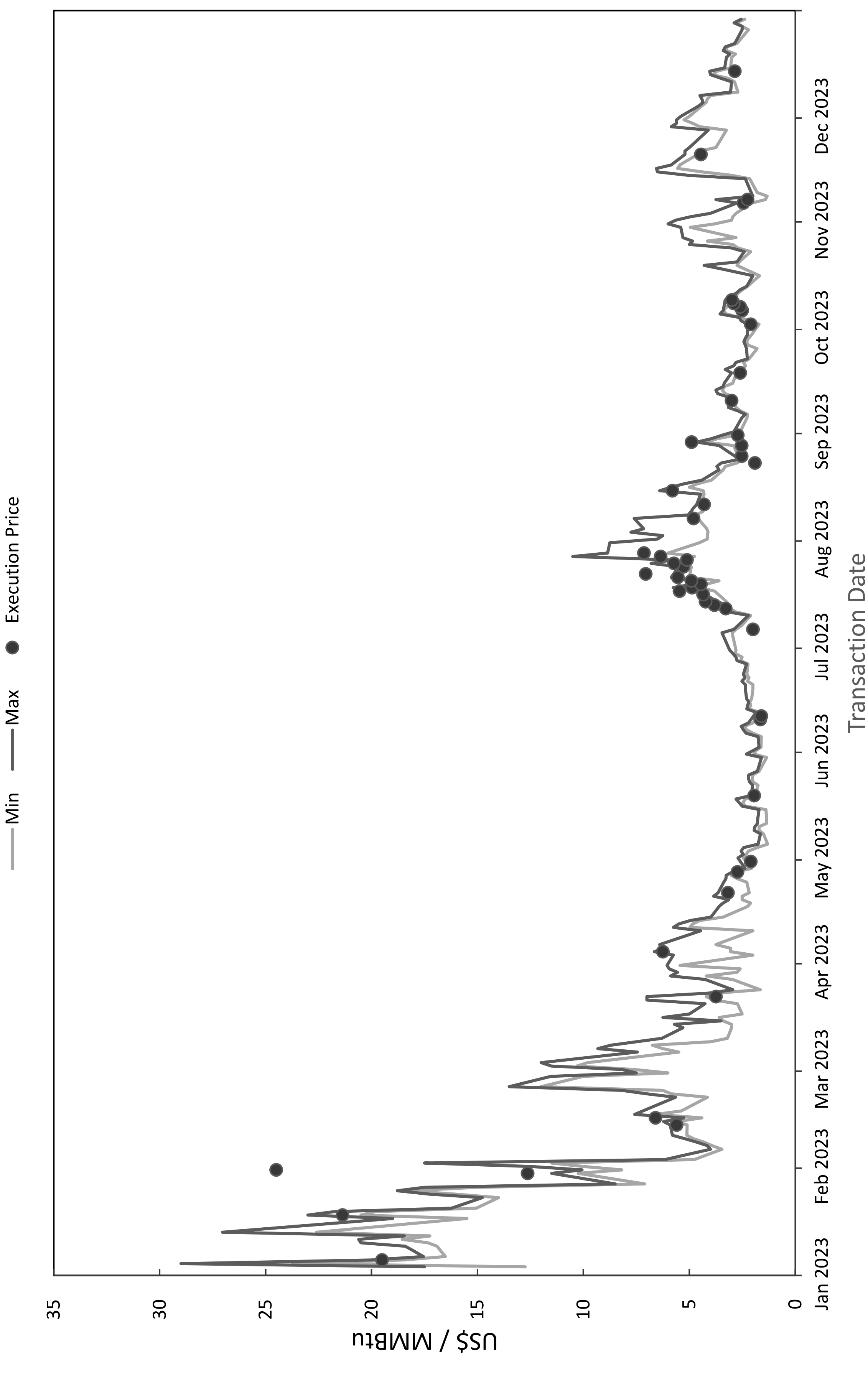
Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

Comparison to Market
Nevada Power Company 2023 NW Opal WY Spot Market Sales

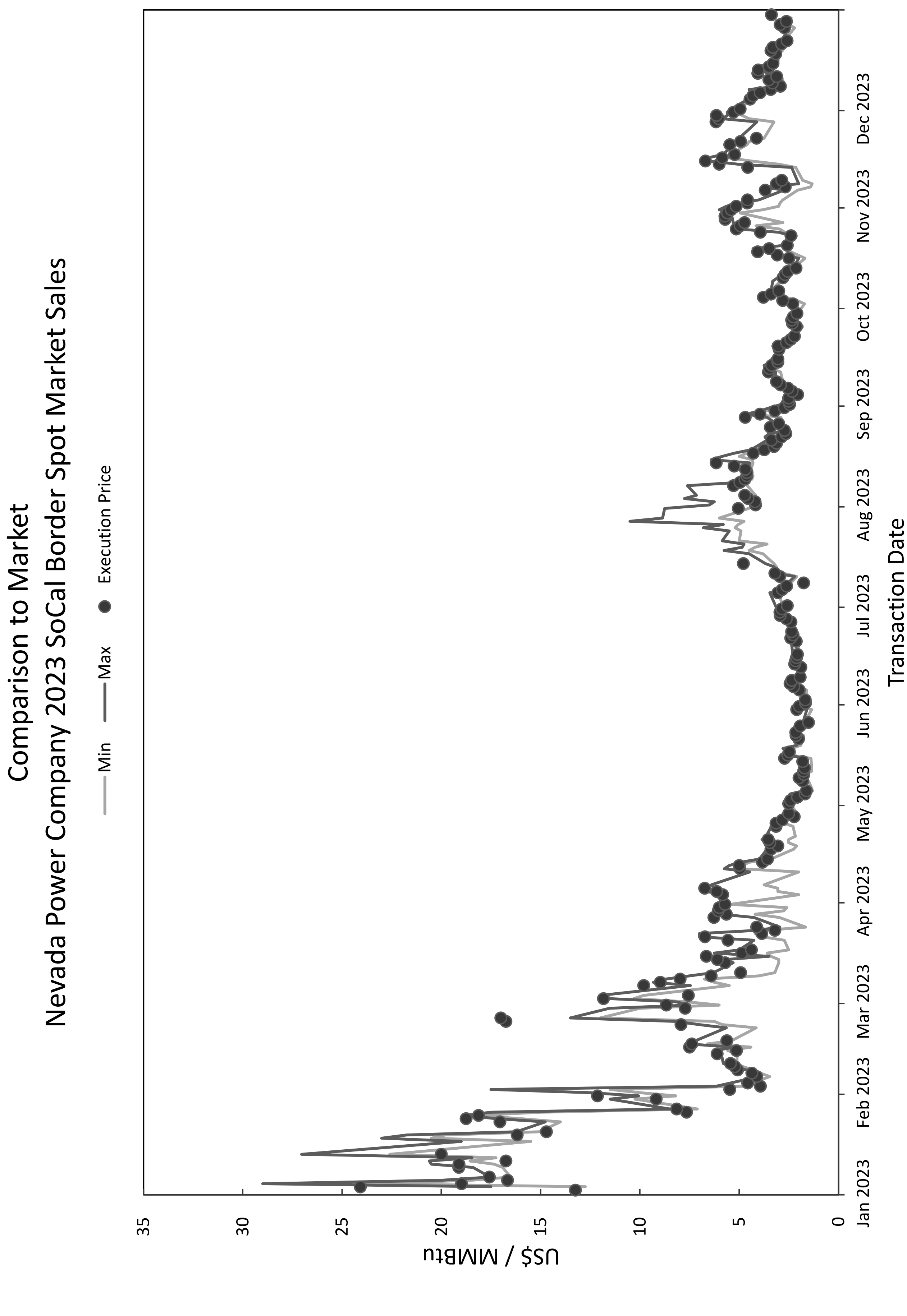


Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

Comparison to Market
Nevada Power Company 2023 SoCal Border Spot Market Purchases



Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.



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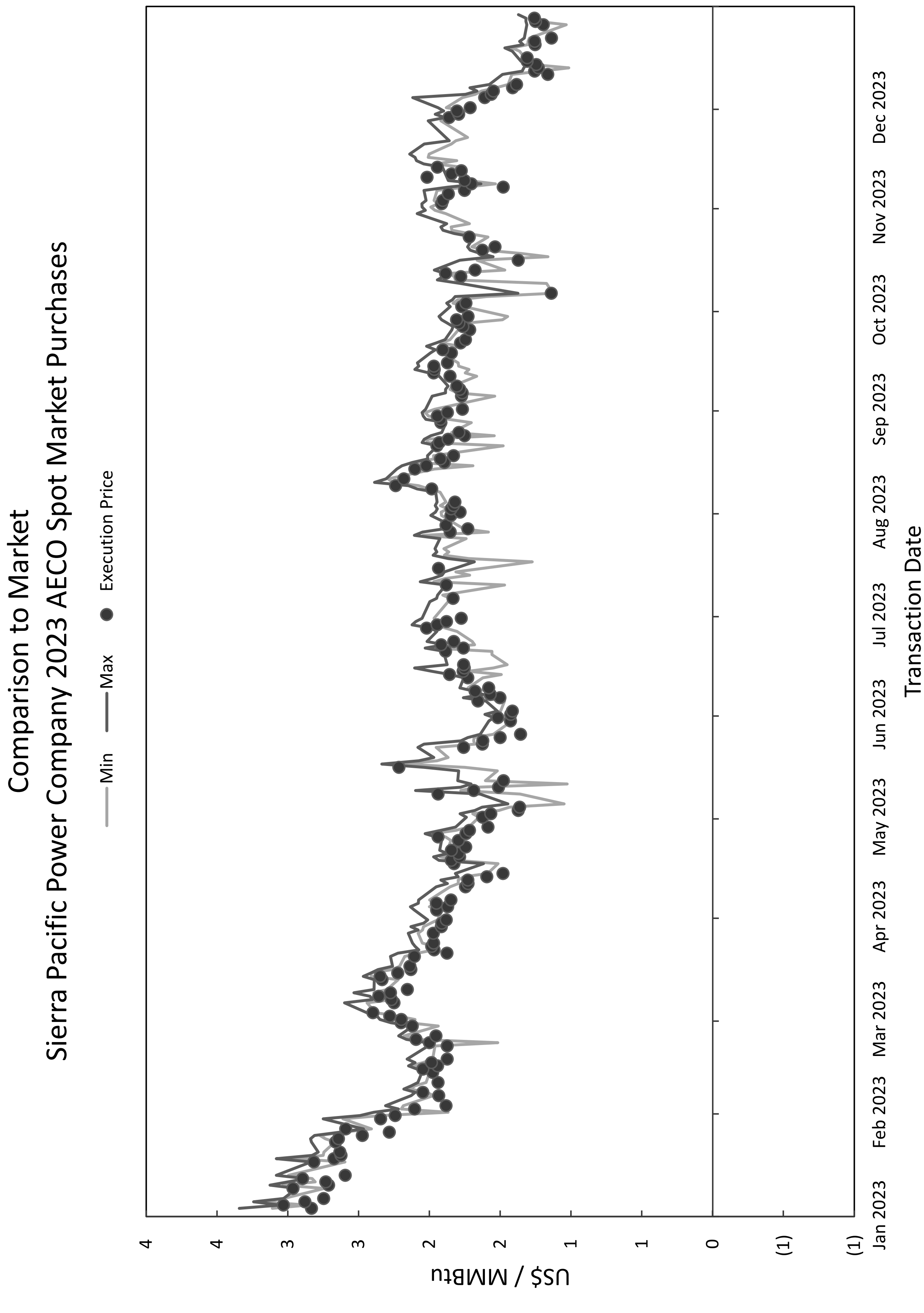
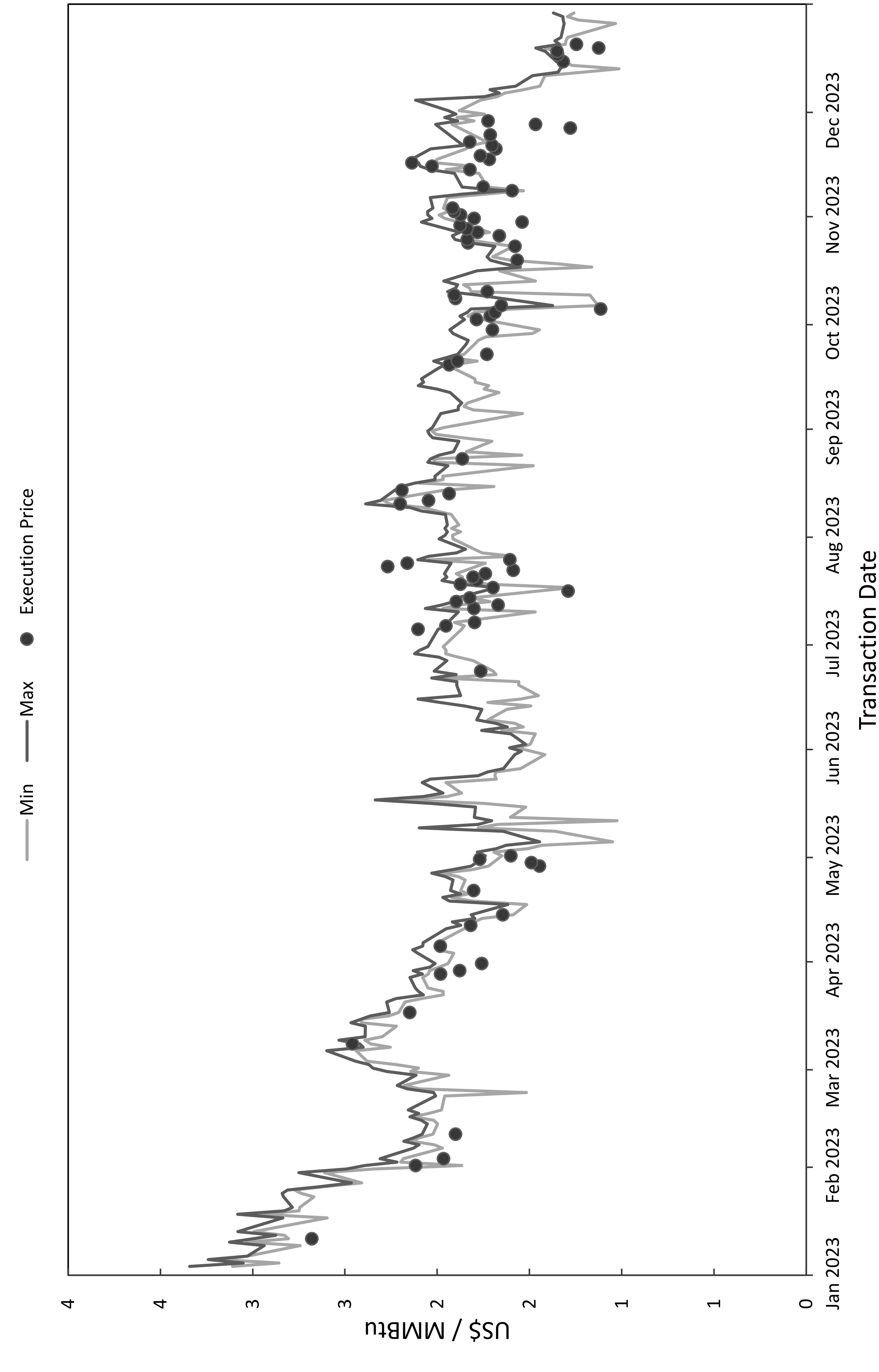


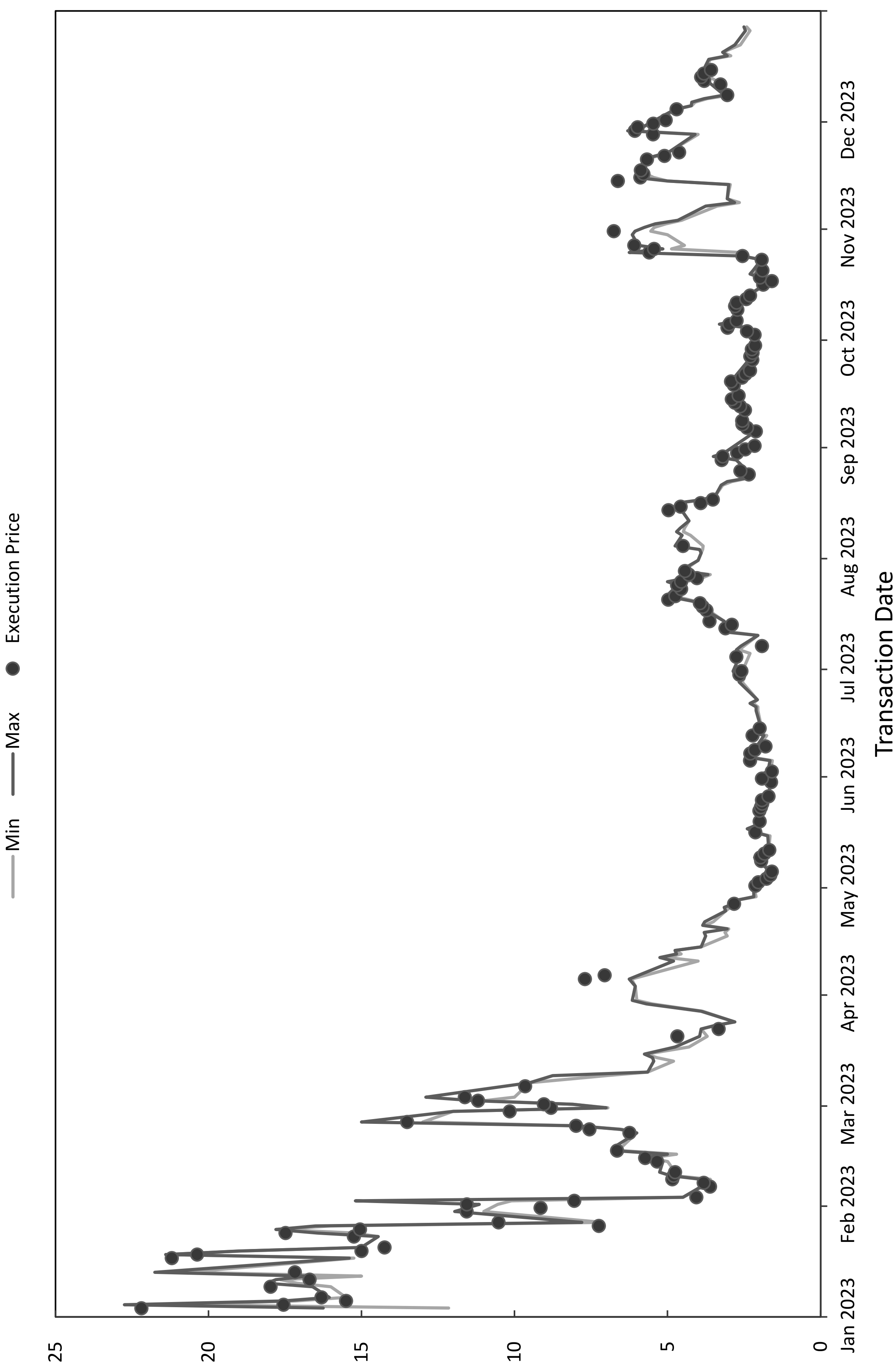
Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

Comparison to Market
Sierra Pacific Power Company 2023 AECO Spot Market Sales



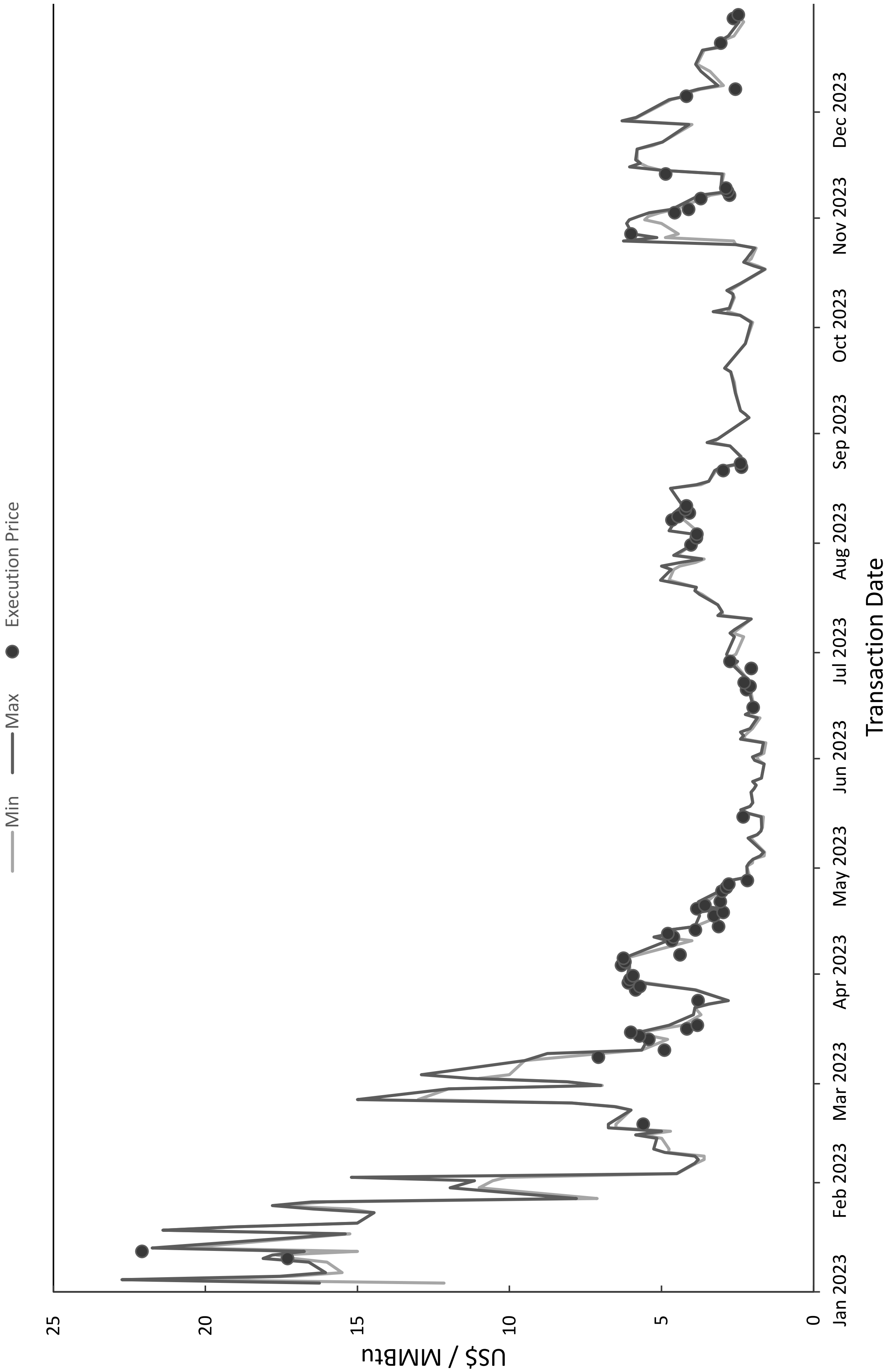
Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

Comparison to Market
Sierra Pacific Power Company 2023 Malin Spot Market Purchases



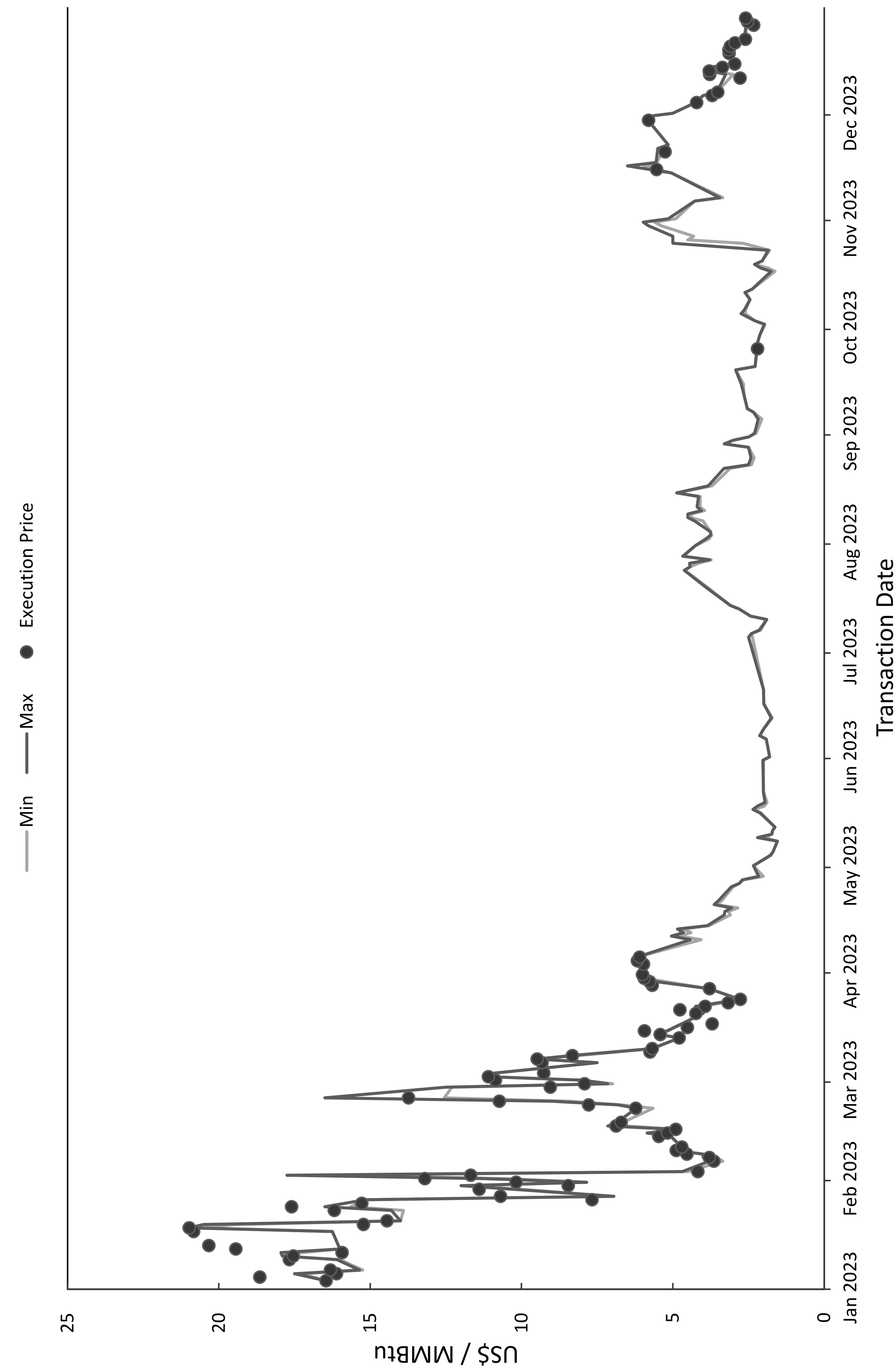
Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

Comparison to Market
Sierra Pacific Power Company 2023 Malin Spot Market Sales



Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

Comparison to Market
Sierra Pacific Power Company 2023 NW Opal WY Spot Market Purchases



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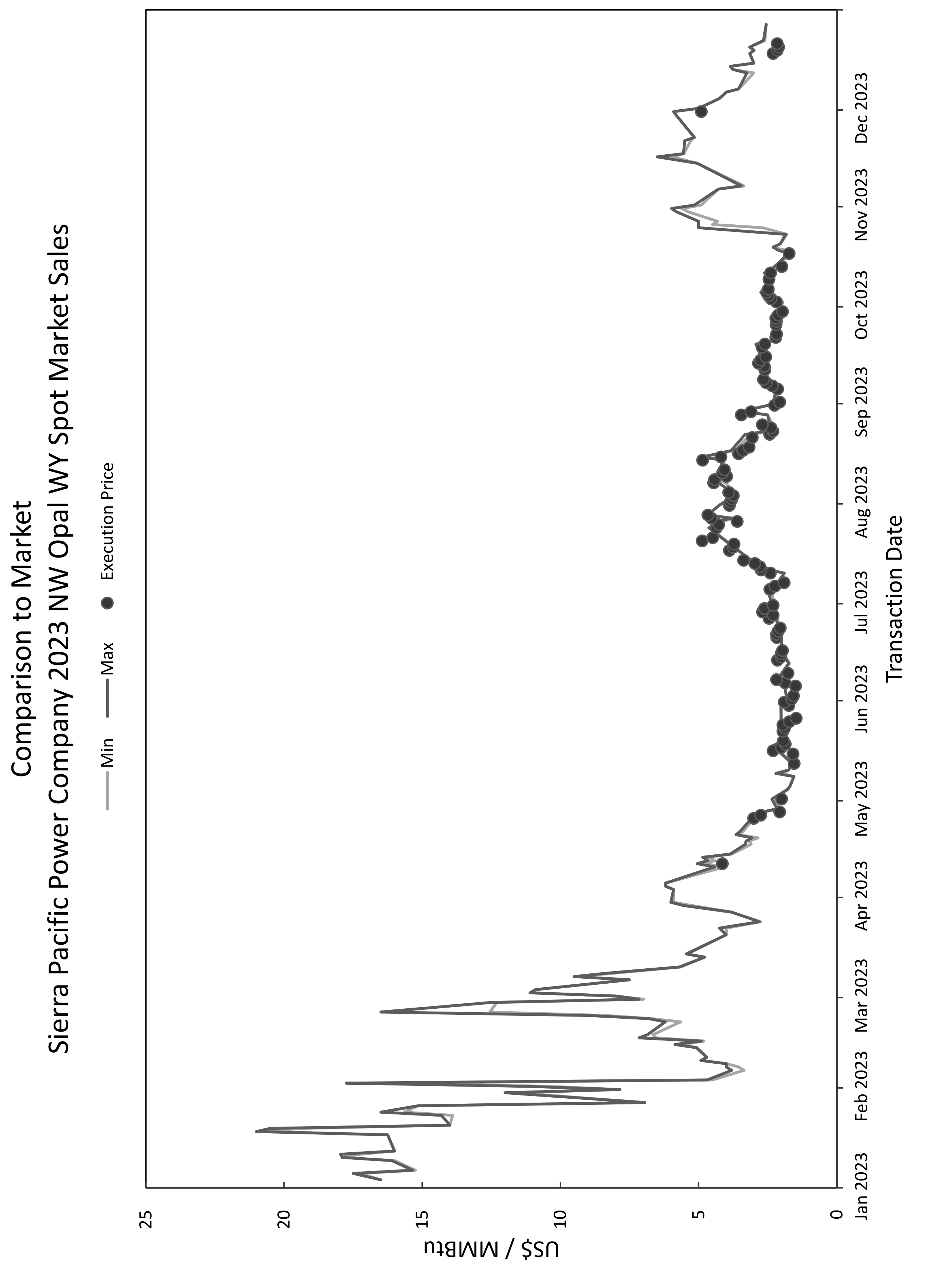
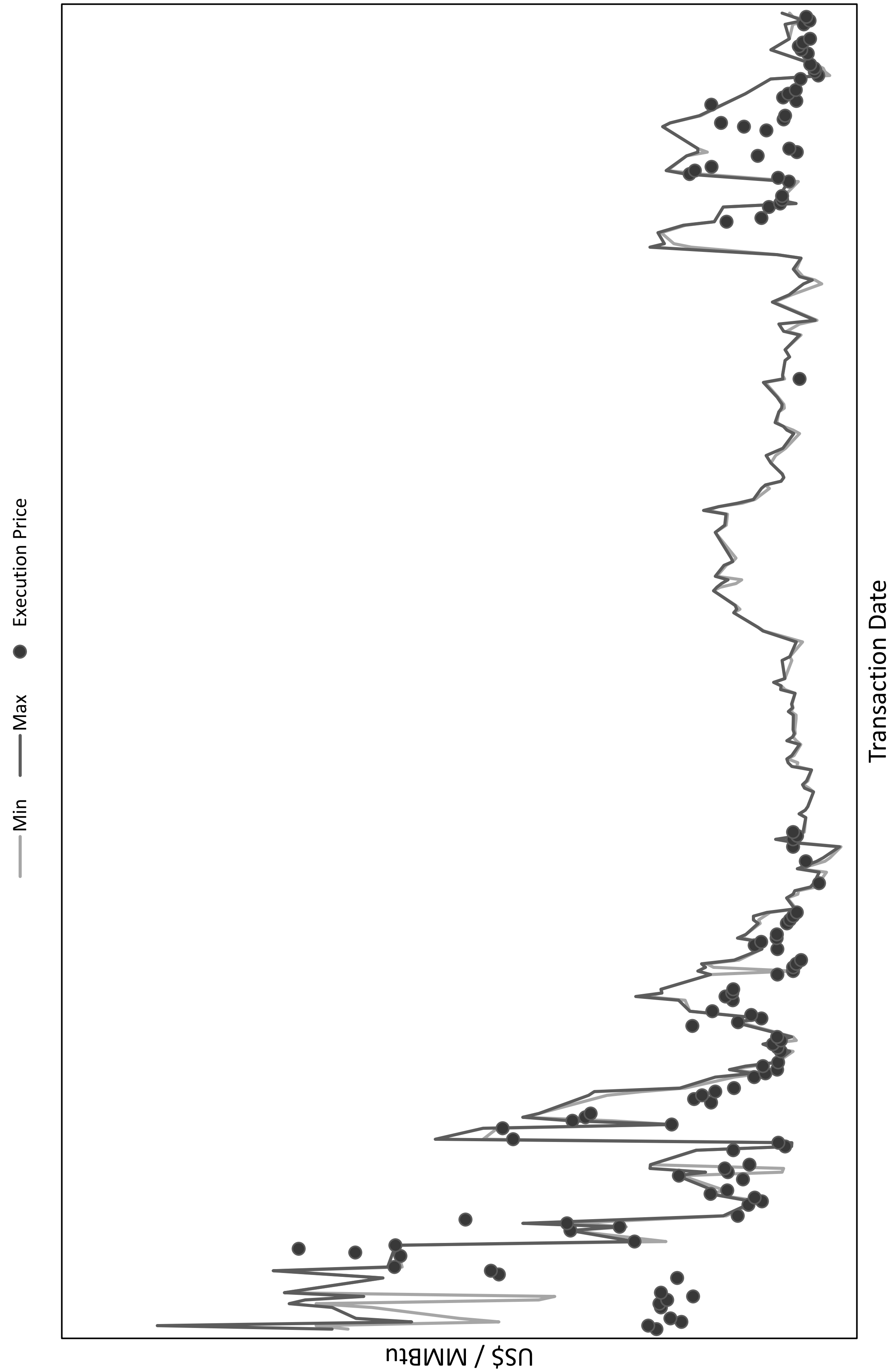


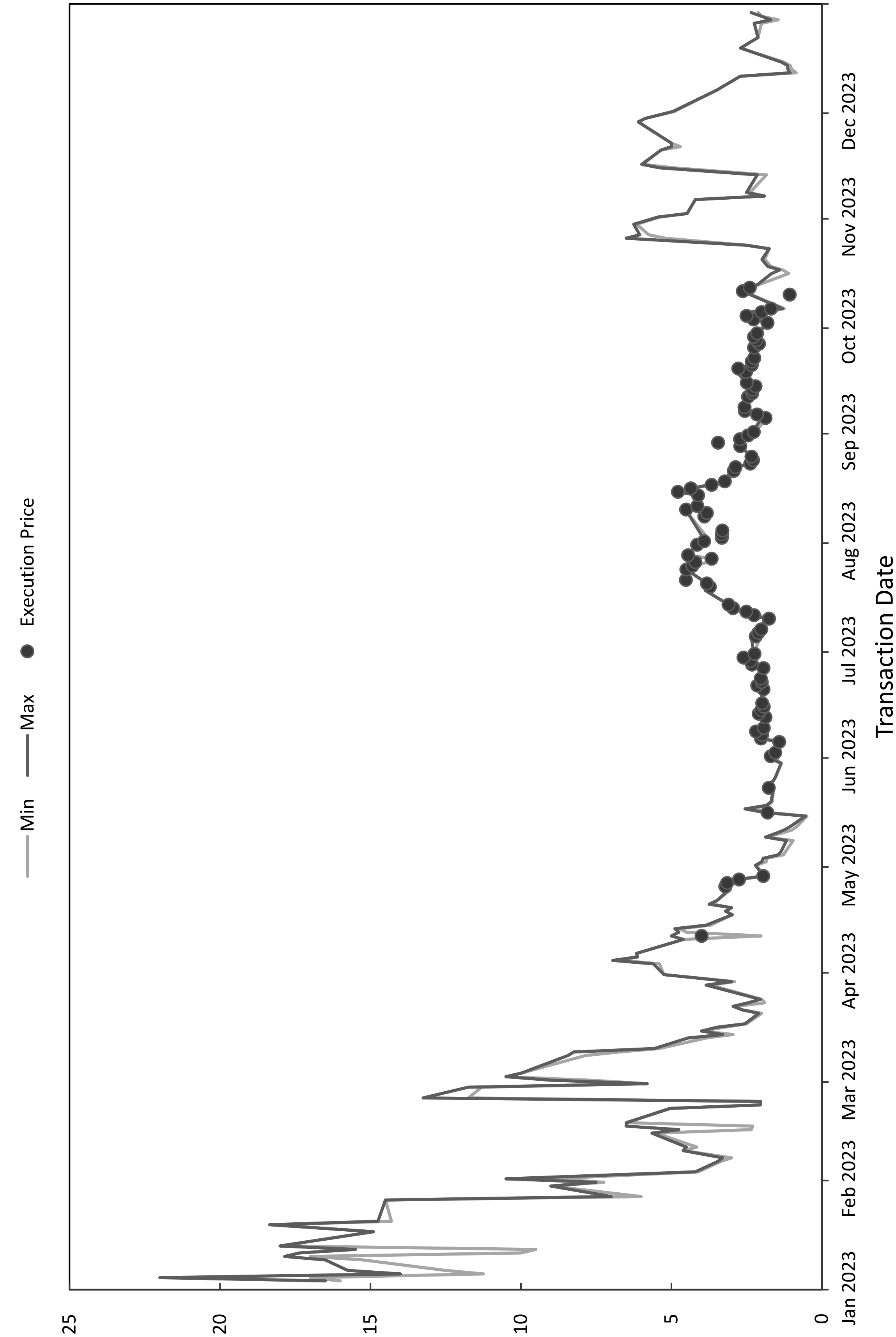
Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

Comparison to Market
Sierra Pacific Power Company 2023 Sumas Spot Market Purchases



Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

Comparison to Market
Sierra Pacific Power Company 2023 Sumas Spot Market Sales



Source: Daily Min and Max Prices from Standard and Poor's Capital IQ Pro. Execution Prices from NV Energy Monaco Transaction Database.

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, KURT STRUNK, 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 under the law of the State of Nevada that the foregoing is true and correct.

Date: March 1, 2024

KURT STRUNK