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by: /s Ashleigh Sternod

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Nevada Power and Sierra Pacific Power

FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 9/1/2023

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2023 Distributed Resources Plan Update as it relates to the Action Plan of their 2022-2041 Joint Integrated Resource Plan.	)	Docket No. 23-09___

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TRANSMITTAL LETTER

September 1, 2023

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

RE: Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2023 Distributed Resources Plan Update as it relates to the Action Plan of their 2022-2041 Joint Integrated Resource Plan.

Dear Ms. Osborne:

Enclosed for filing with the Commission please find the Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (together, "NV Energy") for the approval of their 2023 Distributed Resources Plan Update ("DRP Update") as it relates to the Action Plan of their 2021 Joint Integrated Resource Plan ("IRP"). This Joint Application is made pursuant to Sections 704.9239 and 703.535 of the Nevada Administrative Code ("NAC"). The Joint Application consists of the following:

- Joint Application;
- Draft Notice;
- Distributed Resources Plan Update for 2024;
- Testimony of Joseph Sinobio, Alex Ford, Kimberly Williams, Patricia Rodriguez, Adam Grant, and Michael Brown;
- Technical Appendix consisting of Technical Appendices 1 through 7;
- Certificate of Service.

NV Energy is also providing courtesy copies of the workpapers supporting the filing. The Non-Wires Alternative ("NWA") Screening Analysis Tool MS Excel files support the tables within the DRP Update depicting the NWA analyses and locational net benefits analyses ("LNBA") performed by NV Energy. NV Energy's Marginal Energy Price and Capacity Price forecasts contained within the NWA Screening Analysis Tool spreadsheets contain commercially sensitive information disclosure of which can negatively affect NV Energy's competitive position. NV Energy is providing the sensitive files to the Commission and will also transmit the files to the Regulatory Operations Staff and Bureau of Consumer Protection upon execution of protective agreements. The Companies request that the above-described information not be disclosed to the public and that this information remain confidential for a period of five years, after which the Commission may return or destroy these materials, whichever is most convenient.

Should you have any questions regarding this filing, please contact me at (775) 834-3470 or roman.borisov@nvenergy.com.

Respectfully submitted,

/s/ Roman Borisov
Roman Borisov
Senior Attorney

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APPLICATION

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2023 Distributed Resources Plan Update as it relates to the Action Plan of their 2022-2041 Joint Integrated Resource Plan.	)	Docket No. 23-09___

JOINT APPLICATION

Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, "NV Energy" or the "Companies") respectfully file this Joint Application for approval of their 2023 Distributed Resources Plan Update ("DRP Update") as it relates to the Action Plan of their 2022-2041 Joint Integrated Resource Plan ("IRP") pursuant to Sections 704.9239 and 703.535 of the Nevada Administrative Code ("NAC"). The Joint Application contains the complete analysis that Nevada Power and Sierra used for this DRP Update, which is applicable to the one year remaining in the Action Plan period, 2024.

I. Summary of the Joint Application

1. Through this Joint Application, Nevada Power and Sierra seek Public Utilities Commission of Nevada ("Commission") approval of the 2023 DRP Update pursuant to NAC 704.9241. NV Energy filed its most recent DRP on June 1, 2021 ("2021 DRP"), as part of its IRP filed with the Commission in Docket No. 21-06001 ("2021 IRP") pursuant to Section 704.741(4) of the Nevada Revised Statutes ("NRS"). That IRP filing included a three-year action plan covering 2022-2024. NAC 704.9239 requires NV Energy to file a DRP Update on or before September 1 of the first and second years after the action plan filing applicable for each year remaining in the action plan period. This Joint Application represents NV Energy's compliance with NAC 704.9239 and covers 2024, which is the remaining year of

the three-year action plan that NV Energy filed as part of its IRP filed in Docket No. 21-06001.

II. The Joint Applicants

2. Nevada Power is a wholly-owned subsidiary of NV Energy, Inc., which is itself an indirect subsidiary of Berkshire Hathaway Energy. Nevada Power provides retail electric service to the public in Southern Nevada in portions of Clark and Nye Counties and is a "public utility" as that term is defined and used in NRS 704.741 to 704.751. Nevada Power's principal place of business, mailing address, and telephone number are: 6226 West Sahara Avenue, P.O. Box 98910, Las Vegas, Nevada 89151, 702-402-5000.

3. Sierra is a wholly-owned subsidiary of NV Energy, Inc., which is itself an indirect subsidiary of Berkshire Hathaway Energy. Sierra provides retail electric service to the public in northern Nevada and is a "public utility" as that term is defined and used in NRS 704.741 to 704.751. Sierra's principal place of business, mailing address, and telephone number are: 6100 Neil Road, P.O. Box 10100, Reno, Nevada 89520, 775-834-4011.

4. All correspondence related to this Joint Application should be transmitted to Nevada Power's counsel and to Nevada Power's Manager, Regulatory Services, as set forth below:

Roman Borisov
Senior Attorney
Nevada Power Company
Sierra Pacific Power Company
6100 Neil Road
Reno, NV 89511
Tel: 775-834-3470
roman.borisov@nvenergy.com

Aaron Schaar
Manager Regulatory Services
Nevada Power Company
Sierra Pacific Power Company
6100 Neil Road
Reno, NV 89511
Tel: 775-834-5823
regulatory@nvenergy.com

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III. The Joint Application

5. The Joint Application presents the 2023 DRP Update, Technical Appendices and the prepared direct testimony of six witnesses. The Joint Application, the 2023 DRP Update, the Technical Appendices and the prepared direct testimony contain all of the material facts that NV Energy is prepared to prove in its direct case and provide sufficient evidence to support the relief requested by it.

6. The narrative portion of NV Energy's 2023 DRP Update is organized in 12 sections. Section 1 contains an executive summary of the DRP Update. Section 2 introduces the DRP Update by providing an overview, setting forth the legal underpinnings of the filing, and summarizing the stakeholder engagement[1] and the level of distributed energy resources ("DER") penetration on NV Energy's grid. Section 3 contains the comprehensive, core analyses of the DRP required to understand the locational capabilities of the distribution system to accommodate DER capacity, the needs of the transmission and distribution grids, the ability of DERs to potentially meet those needs cost-effectively, and the potential system and locational benefits of DERs. Section 4 contains NV Energy's first Transportation Electrification Plan ("TEP") update for the three programs approved in Docket No. 22-09006. Section 5 identifies barriers to the cost-effective integration of DERs and includes recommendations to overcome these barriers. Section 6 identifies necessary coordination with the IRP process, other legislative actions, and Commission-approved programs and tariffs. Section 7 discusses NV Energy's publicly-accessible DRP web portal wherein the results of the hosting capacity analyses ("HCA"), non-wires alternative analyses ("NWA"), and locational net benefit analyses ("LNBA") can be viewed and data can be downloaded. Section 8 discusses continued refinement of DRP elements. The Companies will continue to refine these elements, and the timeframes and activities involved serve as the basis for a view moving forward, which is discussed in Section 12. Section 9 discusses ongoing and planned

[1] The stakeholder engagement includes convening a stakeholder process ordered in paragraph 15 of the March 8, 2022, Corrected Modified Final Order in Docket No. 21-06001.

investments in new tools, systems and technologies. Specifically discussed in that section are updates on the Companies' investigation into acquisition of a Distributed Energy Resources Management System ("DERMS") solution and participation in a U.S. Department of Energy ("DOE") grant project entitled "Optimization of Excess Solar & Storage Capacity for Grid Services." Section 10 discusses the Companies' identification of any opportunities in which DRP elements would benefit by conducting a pilot and/or a demonstration project. Finally, the Companies' specific approval requests of the Commission from this DRP Update, including any deviations from the requirements in NAC, are described in Section 11.

7. The 2023 DRP Update is supported by the following witnesses:

Joseph Sinobio, Integrated Grid Planning Manager, describes and summarizes the DRP Update narrative, sponsors the majority of the Sections of the DRP Update, including the distribution planning and integrated grid planning, and introduces other witnesses;

Alex Ford, Transmission Planning Engineer II, supports Section 3.B of the DRP Update narrative and the transmission planning aspects of the DRP contained therein;

Kimberly Williams, Director of Resource Planning and Analysis, supports Section 6.A of the DRP Update narrative, which discusses DRP coordination with other components of the IRP;

Patricia Rodriguez, Director of Energy Services Optimization, supports Section 6.B of the DRP Update narrative, which discusses DRP coordination with existing Commission-approved DER programs;

Adam Grant, Director of Electrification and Energy Services, supports Section 4 and Subsection 6.B.1(c) of the DRP Update narrative, entitled "Transportation Electrification Plan" and "Economic Recovery Transportation Electrification Plan" respectively;

Michael Brown, Director of Energy Services, supports Section 9 of the DRP Update narrative, which discusses incremental investment in tools, systems, and technologies to integrate DER.

8. The Technical Appendix contains (1) Docket No. 21-06001 DRP Stakeholder Process Initial Issues List, (2) Nevada Power and Sierra Past Peaks, (3) Nevada Power and Sierra Forecast Peaks, (4) DER Analytics Toolset and Potential Study Scope of Work, (5) HCA Monthly Update Process Flowchart, (6) NV Energy Standard Loading Criteria, and (7) NV Energy DRP Web Portal User Guide.

IV. Request for Deviation

9. NAC 704.0097 provides that the Commission may allow deviation from any provision of NAC Chapter 704 if:

(1) Good cause for the deviation appears;

(2) The person requesting the deviation provides a specific reference to each provision of the chapter from which the deviation is requested; and

(3) The Commission finds that the deviation is in the public interest and is not contrary to statute.

NV Energy requests deviations from the provisions of NAC 704.9237(2)(f) and 704.9237(3)(b).

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

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

NV Energy utilized the latest available net distribution feeder, substation transformer, and transmission forecasts to determine the constraints on its transmission and distribution ("T&D") systems. However, all distributed resource types as defined in NAC 704.90583 are

not yet represented in those forecasts. The Companies have disaggregated system-level private solar photovoltaic ("PV") forecasts down to the substation and feeder levels, have received an updated electric vehicles ("EV") forecast by census block, and are in the process of developing a method to segregate and allocate the load associated with existing and future EV charging to individual feeders. Also, the Companies have begun developing the requirements for a DER Forecasting and Valuation solution that would ensure that all DER types are forecasted and is presently targeting this effort to be completed in a timeframe that would support the DRP filing that would occur on or before June 1, 2024. In the meantime, NV Energy requests a partial deviation from NAC 704.9237(2)(f) as it continues to finalize the net distribution system load forecasting. The Companies' request to deviate is for good cause because it does not impact the analysis or conclusion of the DRP Update and recognizes the DRP is an evolving process that requires flexibility.

11. NAC 704.9237(3)(b) states that the DRP must include a hosting capacity analysis of the distribution system evaluated *"under normal conditions and planned and unplanned contingency conditions."* The Companies have begun discussing the issue of performing HCA under contingency conditions internally and initially concluded that any contingencies analyzed would need to be limited in scope to ensure that the number of cases analyzed do not create an untenable situation in terms of being able to complete the analysis, especially, considering that the monthly update and annual full-system update processes already take an entire month and an entire quarter to be completed, respectively, with current processes and resources. NV Energy also is investigating how other utilities may be approaching this issue to ascertain whether there are any techniques that can be applied to ensure that the analytical process would not be overburdened by the addition of contingency conditions. NV Energy requests a partial deviation from NAC 704.9237(3)(b) as it continues to finalize the hosting capacity analysis process. The Companies' request to deviate is for good cause because it does not impact the analysis or conclusion of the DRP Update and recognizes the DRP is an evolving process that requires flexibility.

VI. Request for Relief

Nevada Power and Sierra respectfully request that the Commission issue an order that:

A. Grants the Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2023 Distributed Resources Plan Update as it relates to the Action Plan of their 2022-2041 Joint Integrated Resource Plan;

B. Approves the 2023 Distributed Resource Plan Update as compliant with NAC 704.9239 and determines, pursuant to NAC 704.9241 and 704.9494(5), that the elements contained in the 2022 Distributed Resources Plan Update are prudent;

C. Grants the requests for deviation from the provisions of NAC 704.9237(2)(f) and 704.9237(3)(b) described above;

D. Grants all other relief the Commission deems appropriate and necessary.

Submitted this 1st day of September, 2023.

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

By: */s/ Roman Borisov*

Roman Borisov
Senior Attorney
6100 Neil Rd.
Reno, NV 89511
T: 775-834-3470
roman.borisov@nvenergy.com

NARRATIVE

DISTRIBUTED RESOURCES PLAN

NV Energy's
Distributed Resources Plan Update
for 2024

September 1, 2023

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Section 1. Executive Summary

In 2017, the Nevada Legislature enacted Senate Bill 146 ("SB146"), which introduced and established requirements for distributed resources planning in Nevada.[1] Section 704.741(4) of the Nevada Revised Statutes ("NRS") requires the state's two largest electric utilities, Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra"),[2] to prepare and include in their joint triennial integrated resource plan ("IRP") a Distributed Resources Plan ("DRP").[3] NV Energy embraced the DRP concept, preparing and filing one of the first comprehensive and complete DRPs in the nation on April 1, 2019 ("2019 DRP"). NV Energy filed its most recent DRP on June 1, 2021 ("2021 DRP"), as part of its IRP filed with the Public Utilities Commission of Nevada ("Commission") in Docket No. 21-06001 ("2021 IRP"). That IRP filing included a three-year action plan covering 2022-2024.

Additionally, Nevada Administrative Code ("NAC") Section 704.9239 requires that NV Energy file an update of its DRP ("2023 DRP Update" or "DRP Update") on or before September 1st in each of the interim two years between the filing of an action plan.[4] This filing represents NV Energy's compliance with NAC 704.9239 and covers 2024, which is the remaining year of the three-year action plan that NV Energy filed as part of its 2021 IRP. The comprehensive analyses used to prepare this 2023 DRP Update were developed through significant collaboration with stakeholders, many of whom have participated in developing DRP techniques in other jurisdictions.

A formal DRP process should aid in the cost-effective integration of Distributed Resources (also referred to as "Distributed Energy Resources" and "DERs") into the Companies' distribution, transmission, integrated grid, and resource planning processes, and ultimately NV Energy's electric grid. To ensure a thoughtful and structured approach to this new and transformational planning paradigm, NV Energy adopted and continues to pursue a "walk-jog-run" philosophy to work through the implementation and refinement of the various elements of its DRP, drawing in part from models and hypotheses that continue to be discussed and piloted in other jurisdictions. This philosophy was discussed in detail throughout stakeholder workshops held during the development of regulations for the DRP[5] to establish a baseline and understanding that a

[1] SB146 is codified in NRS 704.741(4).

[2] Together, Nevada Power and Sierra are referred to as "NV Energy", the "NV Energy utilities", or the "Companies."

[3] NRS 704.741(7)(b) defines Distributed Resources as "distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies."

[4] NAC 704.9239 requires that NV Energy file an update of its DRP "on or before September 1 of the first and second years after the action plan of a utility is filed…applicable for each year remaining in the period covered by the action plan."

[5] The Commission conducted a rulemaking to implement SB146 through Docket No. 17-08022 and adopted temporary regulations for the implementation of SB146 in an Order dated October 8, 2018, in that docket. The Commission submitted the temporary regulations to the Legislative Counsel Bureau ("LCB") and the Office of the Secretary of State on November 15, 2018, and received the temporary regulations back from the LCB in revised form on August 8, 2019. The Commission then issued an Order on September 13, 2019, adopting the revised temporary regulations as permanent. Subsequently, the regulations were incorporated into NAC.

refinement process for many of the DRP elements would occur over time following the initial filing of the DRP. The Commission reaffirmed its continued support of this philosophy in its Corrected Modified Final Order in Docket Nos. 21-06001 and 21-06002.[6]

Section 3 contains the comprehensive, core analyses of the DRP required to understand the locational capabilities of the distribution system to accommodate DER capacity, the needs of the transmission and distribution grids, the ability of DERs to potentially meet those needs cost-effectively, and the potential system and locational benefits of DERs. Consistent with the DRP regulations, the Companies used six-year load and DER growth forecasts for their electric grids beginning with the year after this plan is being filed (*i.e.,* 2024-2029).[7]

The analyses in this DRP Update begin with the Hosting Capacity Analysis ("HCA"), which determines the amount of DER capacity that can be accommodated on a particular distribution feeder section without adversely impacting safety, power quality, reliability, or other operational criteria. The HCA performed by the Companies for this DRP Update filing relied on advanced electrical simulation software to model the distribution system and calculate the amount of incremental DER capacity (*i.e.*, the amount of capacity above what may already exist) that can be accommodated without violating any of the established criteria. This methodology is more analytically efficient than an iterative approach and is bolstered by utilization of a substantial volume of 15-minute loading data. Analytical cases for distributed generation ("DG"), solar photovoltaic ("PV") generation, and load were used to identify the potential incremental DER hosting capacity for each distribution feeder section. The results of the HCA can be viewed and downloaded via a publicly-accessible web portal developed by NV Energy.[8]

The other major analytical process in this DRP Update is the Grid Needs Assessment ("GNA"). Through a suitability and screening process, the GNA identifies constraints on the Companies' electric grid and the planned traditional wired capital upgrade solutions in 2024 required to address these constraints. Next, potential Non-Wires Alternative ("NWA") solutions in multiple years were identified and analyzed using a spreadsheet-based NWA Screening Analysis Tool that quantified the needs of the system and identified an NWA solution portfolio potentially containing five different DER technologies that satisfies those needs. In total, the Companies performed eight NWA analyses for distribution system constraints and two for transmission system constraints in the 2024 timeframe for this DRP Update.

Within the NWA Screening Analysis Tool, the Companies determined "ballpark" capital cost estimates for the NWA portfolio solutions and performed detailed Present Worth of Revenue Requirement ("PWRR") analyses comparing the PWRR of installing traditional wired solutions in their planned in-service years against the PWRR of deferring the installation of the traditional

[6] March 8, 2022, Corrected Modified Final Order at 138, para. 350.
[7] NAC 704.9237(2)(f).
[8] Accessible via this link: https://drp.nvenergy.com.

wired solutions to a later year while installing the NWA portfolio solutions of sufficient capacity to mitigate the identified constraint forecasted in the appropriate year. The PWRR analyses for the NWA portfolio solutions included quantified potential location-specific and system-wide benefits in addition to costs for those options, thus serving as the Locational Net Benefits Analysis ("LNBA").

Finally, to identify instances where NWA portfolio solutions may be potentially cost-effective in deferring or displacing traditional wired capital investments, the PWRRs of those solutions were compared against the differences between the PWRRs of the traditional wired solutions installed in their planned in-service years and the PWRRs of the deferred traditional wired solutions.[9] Instances where the PWRRs of the NWA portfolio solutions (the LNBAs) were lower than the differences between the PWRRs of the traditional wired solutions in their planned in-service years and the deferred traditional wired solutions were considered for further review to refine NWA technology solution sizing, costs, and gauge practical feasibility considerations such as locating of the DER technologies identified in the NWA portfolio solutions.

In accordance with 2021 Nevada Senate Bill 448 ("SB448") establishing a new requirement for the DRP to contain a Transportation Electrification Plan ("TEP"), Section 4 provides an update of NV Energy's first TEP that was filed in Docket No. 22-09006 as an amendment to the Companies' 2021 DRP. Subsequently, future TEPs will be part of future DRPs beginning in 2024.

Consistent with NRS 704.741(4) and NAC 704.9237, NV Energy identified barriers to the cost-effective integration of DERs and included recommendations to overcome these barriers in Section 5, and identified necessary coordination with the IRP process, other legislative actions, and Commission-approved programs and tariffs in Section 6. Section 7 discusses NV Energy's publicly-accessible DRP web portal wherein the results of the HCA, NWA, and LNBA analyses can be viewed, and data can be downloaded.

While not required in NRS 704.741(4) or NAC 704.9237, the information in Section 8 serves to reinforce the fact that, in keeping with a "walk-jog-run" approach, many of the DRP elements are still evolving. With the overall DRP currently in its "jog" stage, many of these elements have progressed past the initial phase while not yet achieving maturity in how NV Energy will eventually complete the necessary analyses and the information that will be provided in the DRP. The Companies will continue to refine these elements, and the timeframes and activities involved serve as the basis for a view moving forward, which is discussed in Section 12.

In working through the DRP elements and progressing the DRP concepts, the Companies may identify areas that could benefit from investment in new tools, systems and/or technologies. Any

[9] The PWRRs of the deferred traditional wired solutions were always lower than the PWRRs of the traditional wired solutions in their planned in-service years, thus the differences, or savings, between the two were always a positive value. This positive value deferral benefit (savings) was then compared to the net cost of the NWA portfolio solution required to achieve the deferral.

such ongoing or planned investment is discussed in Section 9. Specifically discussed in that section are updates on the Companies' investigation into acquisition of a Distributed Energy Resources Management System ("DERMS") solution, and participation in a U.S. Department of Energy ("DOE") grant project entitled "Optimization of Excess Solar & Storage Capacity for Grid Services."[10]

Section 10 discusses the Companies' identification of any opportunities in which DRP elements would benefit by conducting a pilot and/or a demonstration project. Specifically, this section discusses the results of a geo-targeted Demand Response ("DR") demonstration project at the Bicentennial Substation in summer 2022.

Finally, the Companies' specific approval requests of the Commission from this DRP Update, including any deviations from the requirements in NAC, are described in Section 11.

[10] These projects were approved in the March 8, 2022, Corrected Modified Final Order for Docket Nos. 21-06001 and 21-06002 at 153, para. 385-87, and at 159-60, para. 401-04.

Section 2. Introduction

A. Distributed Resources Plan Alignment with NV Energy Core Principles

As NV Energy worked with stakeholders in developing the initial 2019 DRP filing, the Companies sought to ensure that the effort adhered to the highest standards in the industry and aligned with NV Energy's Core Principles. These principles are outlined in DRP Update-Table 1 below:

DRP UPDATE-TABLE 1:
DRP OBJECTIVES ALIGN WITH NV ENERGY CORE PRINCIPLES

Core Principle	Description	DRP Alignment
Customer Service	Focus on delivering reliability, dependability, low prices, exceptional service, and innovative solutions customers want and need.	Investigate ways to expand the DER footprint on the electric grid. Support DER integration in the locations that provide net value to customers. Propose new programs utilizing DERs.
Employee Commitment	Equip employees with the resources and support they need to be successful, encourage teamwork and provide a safe, rewarding, equitable and inclusive work environment, and make no compromise when it comes to safety and security.	Enhance coordination between NV Energy business units and allocate resources to effectively plan for greater DER penetration.
Environmental Respect	Committed to using natural resources wisely and protecting our environment for the benefit of future generations.	Integrate cost-effective renewable DER onto the grid in support of state and federal greenhouse gas and renewable goals and policies.
Regulatory Integrity	Adhere to a policy of strict regulatory compliance and pursue frequent, open communication with regulators.	Continue collaborative stakeholder meetings. Comply with and seek out opportunities to support legislative and regulatory goals and objectives related to DER.
Operational Excellence	Pride ourselves on excellence in every aspect of our work, meet and exceed our customers' expectations, perform our work safely, and preserve our assets.	Proactively adopt and evolve DER planning activities. Ensure the safety and reliability of the grid while expanding the DER footprint on the electric grid.
Financial Strength	Be excellent stewards of our substantial financial resources, invest in hard assets, and focus on long-term opportunities that will contribute to the future strength of the company.	Invest in cost-effective DER that defer traditional capital infrastructure investments and reduce costs for customers. Make prudent investments that help ensure distribution network optimization. Maximize the utilization of existing assets.

B. Overview of DRP Update Contents

This 2023 DRP Update meets all of the requirements of NRS 704.741(4), NAC 704.9237, and NAC 704.9239 with the exception of a few parts of the regulations from which the Companies are requesting deviation as noted in Section 11.B.[11]

Establishing a formal DRP process as part of an IRP required NV Energy to modify its transmission and distribution planning paradigms, develop new planning processes, procedures and tools, and coordinate amongst several departments, including: Distribution Planning, Integrated Grid Planning, Customer Operations, Demand Side Management, Demand Response, Renewable Programs, Transportation Electrification, Resource Planning, Legal, Rates & Regulatory, Renewable Energy, Transmission Planning, IT, Operations, and Project Management. This integrated planning view aligns with best practices in the industry as the evolution toward higher penetration of DERs on utility electrical systems continues to progress.

In 2022, NV Energy created a new business unit, Integrated Energy Services, that brings together the demand-side customer programs (energy efficiency ("EE"), DR, renewable energy, battery storage ("BESS") and electric vehicles ("EVs")) with the integrated grid planning function. This group facilitates a holistic customer experience across NV Energy programs ensuring the maximizing of DER grid integration and benefits. Additionally, new programs and system investments facilitate utility ownership of DERs including EV infrastructure, community-based solar PV resources and distributed storage for operational needs.

Based upon the requirements of NRS 704.741(4) and through industry research and discussion, informal stakeholder workshops and formal workshops convened to develop the regulations governing the DRP, the Companies have leveraged the efforts of utilities in other jurisdictions, adopting and adapting concepts and processes as appropriate for Nevada. As was discussed in detail in the initial stakeholder workshops and in subsequent DRP filings, the Companies adopted a "walk-jog-run" approach to implement the elements of NRS 704.741(4) and NAC 704.9237.

Consistent with the DRP filings as part of NV Energy's triennial IRP filings, this 2023 DRP Update focuses on four foundational elements of the DRP process. First is the HCA, which relies on robust data on the loading profile of feeders to determine the amount of incremental DER capacity that can be installed on a feeder section without requiring significant upgrades to preclude violation of planning and operational criteria. NV Energy's HCA is a multi-year analysis relying on local load forecasts and data on the penetration and characteristics of interconnected DERs. Industry stakeholders have emphasized that the results of the HCA must be accessible to guide stakeholders to the areas of the NV Energy system where DERs can be cost-effectively integrated and in what

[11] Pursuant to NAC 704.0097, the Companies seek specific waivers from portions of the regulation in the Joint Application.

amounts. NV Energy's publicly-accessible DRP Web Portal provides this view into the Companies' distribution systems.

Second is the GNA that identifies constraints on the electric transmission and distribution grids within a specified timeframe (2024 in this 2023 DRP Update) and provides the identifying information and quantitative characteristics associated with them. Third, the NWA screening analysis within the GNA identifies DER portfolio solutions suitable to mitigate those constraints. The final part of the NWA screening analysis, the LNBA, provides a comparative economic analysis including costs and benefits between the traditional wired solutions to identified constraints and the identified DER portfolio solutions and deferred traditional wired solutions, ensuring that a least-cost solution is recommended and implemented to the benefit of NV Energy's customers.

In accordance with SB448 establishing a new requirement for the DRP to contain a TEP, Section 4 provides an update of NV Energy's first TEP that was filed in Docket No. 22-09006 as an amendment to the Companies' 2021 DRP. Subsequently, future TEPs will be part of future DRPs beginning in 2024.

Identified barriers to the cost-effective integration of DERs and recommendations to overcome these barriers are discussed in Section 5, and identified necessary coordination with the IRP process, other legislative actions, and Commission-approved programs and tariffs are discussed in Section 6. Section 7 discusses NV Energy's publicly-accessible DRP web portal wherein the results of the HCA, NWA, and LNBA analyses can be viewed, and data can be downloaded.

The information in Section 8 serves to reinforce the fact that, in keeping with a "walk-jog-run" approach and although the overall DRP process is in its "jog" phase, most of the DRP elements are still evolving. This section provides some details regarding these refinements. The Companies will continue to refine these elements, and the timeframes and activities involved serve as the basis for a view moving forward through the "jog" phase and beyond, which is discussed in Section 12.

Any ongoing or planned investment in new tools, systems and/or technologies is discussed in Section 9. Specifically discussed in that section are updates on the Companies' investigation into acquisition of a DERMS solution, and participation in a DOE grant project entitled "Optimization of Excess Solar & Storage Capacity for Grid Services."

Section 10 discusses the Companies' identification of any opportunities in which DRP elements would benefit by conducting a pilot and/or a demonstration project. Specifically, this section discusses the results of a geo-targeted Demand Response ("DR") demonstration project at the Bicentennial Substation in summer 2022.

Finally, the Companies' specific approval requests of the Commission from this DRP Update, including any deviations from the requirements in NAC being requested of the Commission, are described in Section 11.

C. Legislative and Regulatory Requirements

NRS 704.741(4) sets forth six elements that must be included in a DRP. Specifically, a DRP must:

(a) Evaluate the locational benefits and costs of distributed resources. This evaluation must be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits and any other savings the distributed resources provide to the electricity grid for this State or costs to customers of the electric utility or utilities.

(b) Propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy the objectives for distribution planning.

(c) Propose cost-effective methods of effectively coordinating existing programs approved by the Commission, incentives and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

(d) Identify any additional spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding a net benefit to the customers of the electric utility or utilities.

(e) Identify barriers to the deployment of distributed resources, including, without limitation, safety standards related to technology or operation of the distribution system in a manner that ensures reliable service.

(f) Include a transportation electrification plan as required by NRS 704.7867.

NAC 704.9239 sets forth the requirements for an update of the DRP, specifically:

1. Beginning in calendar year 2020, on or before September 1 of the first and second years after the action plan of a utility is filed, the utility shall file an update of the distributed resources plan that will be applicable for each year remaining in the period covered by the action plan.
2. The update of the distributed resources plan must comply with the requirements of NAC 704.9237.

Each of the above requirements is addressed in this 2023 DRP Update.

D. Stakeholder Engagement

In developing the 2019 DRP, NV Energy adopted an active and focused stakeholder engagement process comprised of multiple workshops, modeling efforts that had worked well in other states such as California, Hawaii and New York. These workshops ensured that discussions were focused on specific issues and decision points, a wide range of meaningful input was solicited, subject matter experts were engaged on technical issues, constructive working relationships among stakeholders, regulators, and utilities were developed, and common ground on key issues and vocabulary was built, bridging different positions earlier than in a formal regulatory proceeding. This process fostered transparency, predictability, and buy-in from the different stakeholder groups.

1. April 27, 2023, Stakeholder Meeting

In accordance with NAC 704.9237(3)(e), NV Energy hosted an informal workshop on April 27, 2023, within which the Companies provided an update on its HCA process. NV Energy presented the status of its HCA efforts and methods, and presented the following list of recent improvements to the HCA process:

- Improved modeling of primary metered loads through use of metered peak load and loading profiles;
- Improved efficiency of the initial model cleanup process;
- Incorporated more accurate substation transformer impedance data;
- Improved meter load profiles in Synergi by running the 576 analyses;
- Improved Synergi calculations by using a program to remove most of the wandering laterals in the model;
- Improved the efficiency of the programs checking the HCA results and transferring profiles into the models;
- Improved the model by turning off capacitors that were put in a temporary state over a year ago; and
- Improved efficiency in creating recipe files for HCA runs.

At that workshop, NV Energy also indicated that the following items were planned or being considered in the future:

- Improved inverter modeling (smart inverter capabilities);
- Energy storage device modeling;
- Electric vehicle modeling;

- Model Distributed Generation growth as a separate generator to enable future inverter settings changes; and
- Upgrade Synergi to Version 7.

Section 3.A.2 below discusses NV Energy's activities in HCA and real-time hosting capacity in detail and encompasses the related information that was discussed in the April 27, 2023, meeting.

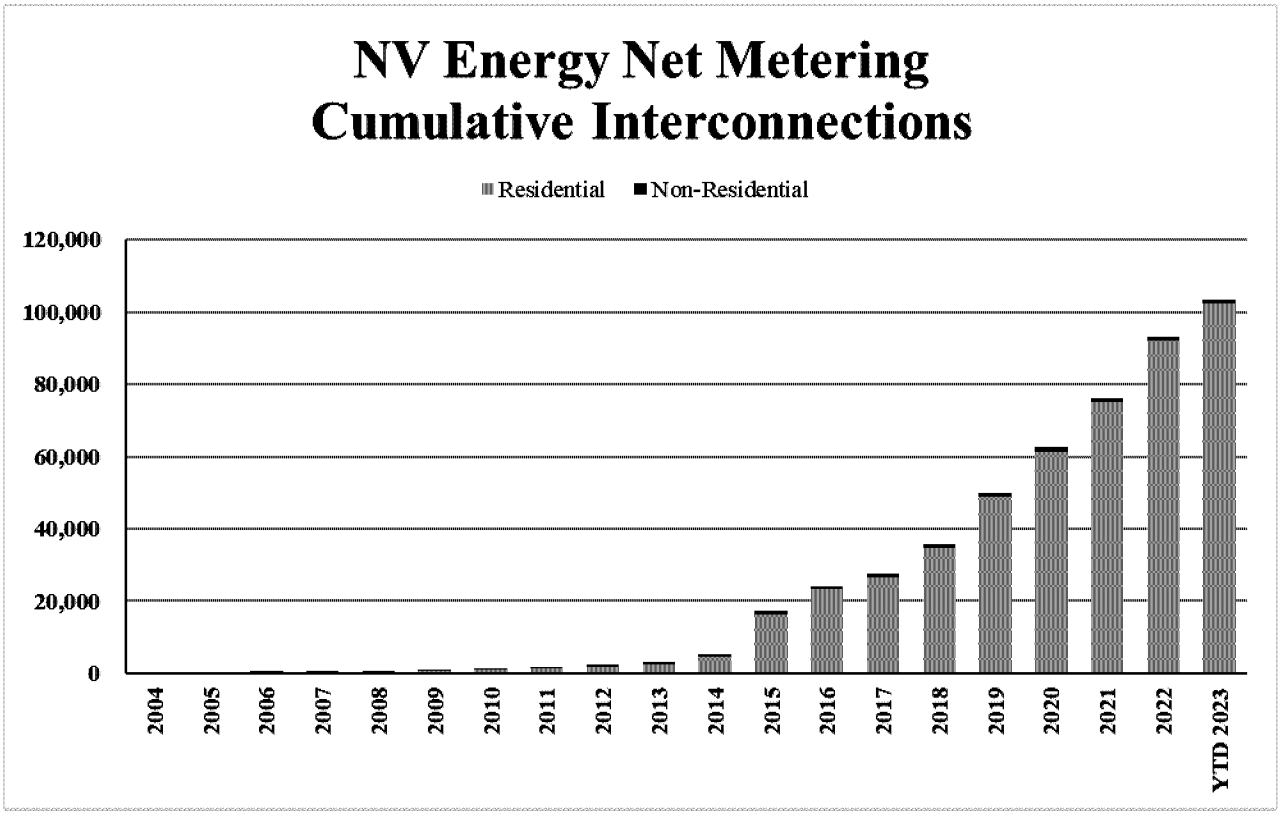
2. DRP Stakeholder Process from Docket No. 21-06001

Intervener testimony in the 2021 DRP filing in Docket No. 21-06001 indicated concerns with a number of the assumptions and techniques the Companies used in developing the DRP. The Commission did not directly address these issues in its final order in that docket but ordered NV Energy to convene a stakeholder process to consider and address the concerns raised in intervener testimony. The Companies convened this process on December 15, 2022. **Technical Appendix DRP Update-1** provides the initial issues list that was established. A bi-monthly meeting schedule with interested stakeholders was established, with meetings held in March, April, June, and August of 2023 prior to this filing. This stakeholder process will continue as necessary to ensure the Companies' compliance with Directive 15 of the final order in Docket No. 21-06001 and NV Energy will report on the results of that process in its 2024 DRP filing.

E. DER Penetration on NV Energy's Grid

As of June 30, 2023, the penetration level of net energy metering ("NEM") on NV Energy's electric distribution system had grown significantly in the last several years to approximately 7.44 percent (total net metering premises/total customers), 103,470 total NEM premises and more than 851 MW of total installed NEM capacity. DRP Update-Figure 1 below shows cumulative residential and non-residential NEM interconnections by year.

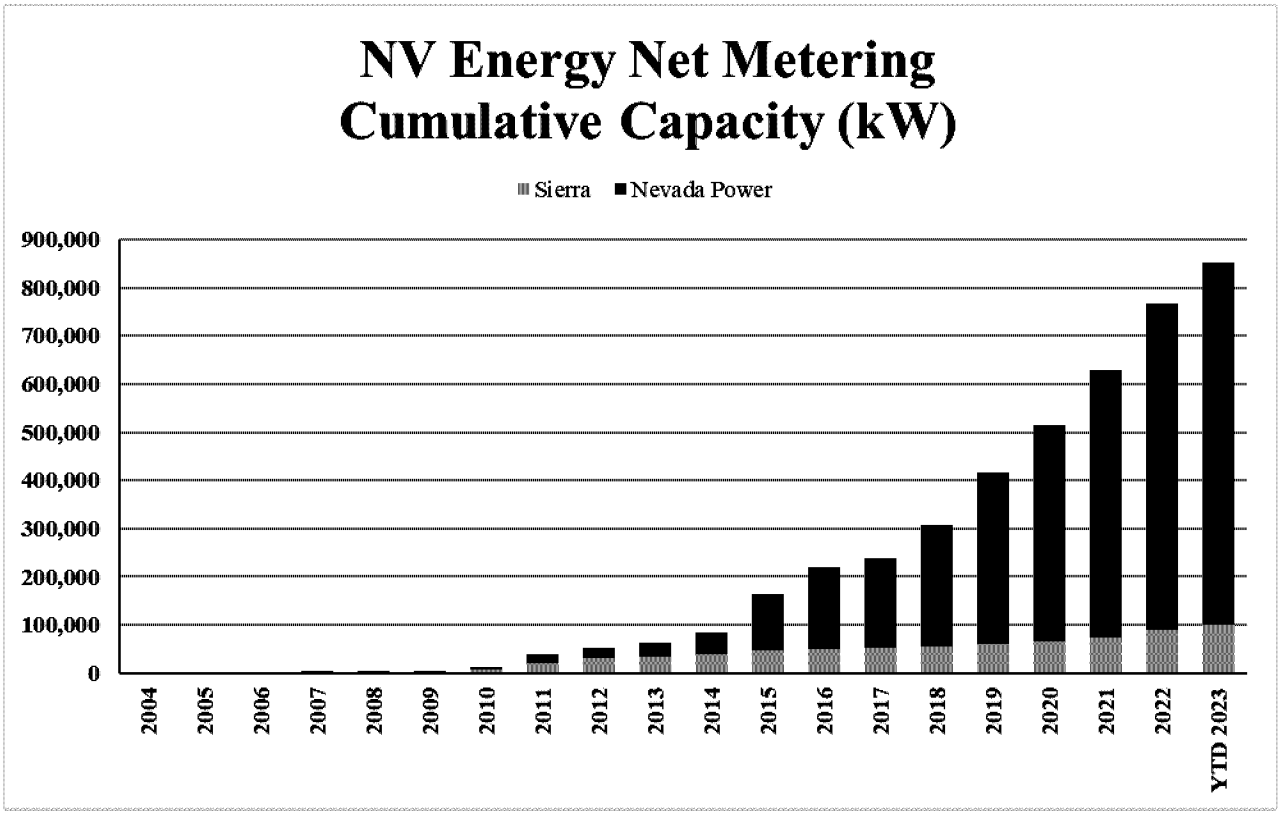
DRP UPDATE-FIGURE 1:
NV ENERGY NET METERING CUMULATIVE INTERCONNECTIONS[12]



DRP Update-Figure 2 below shows cumulative NEM capacity by Company by year.

[12] Figure taken from monthly information provided by NV Energy's Renewables department as of June 30, 2023.

DRP UPDATE-FIGURE 2:
NV ENERGY NET METERING CUMULATIVE CAPACITY[13]



The vast majority of DG assets on NV Energy's distribution system consists of NEM private solar (98.7 percent). DRP Update-Table 2 below provides the total capacity of the different types of installed NEM as of June 30, 2023.

DRP UPDATE-TABLE 2:
INSTALLED NEM RESOURCE CAPACITY AS OF JUNE 30, 2023[14]

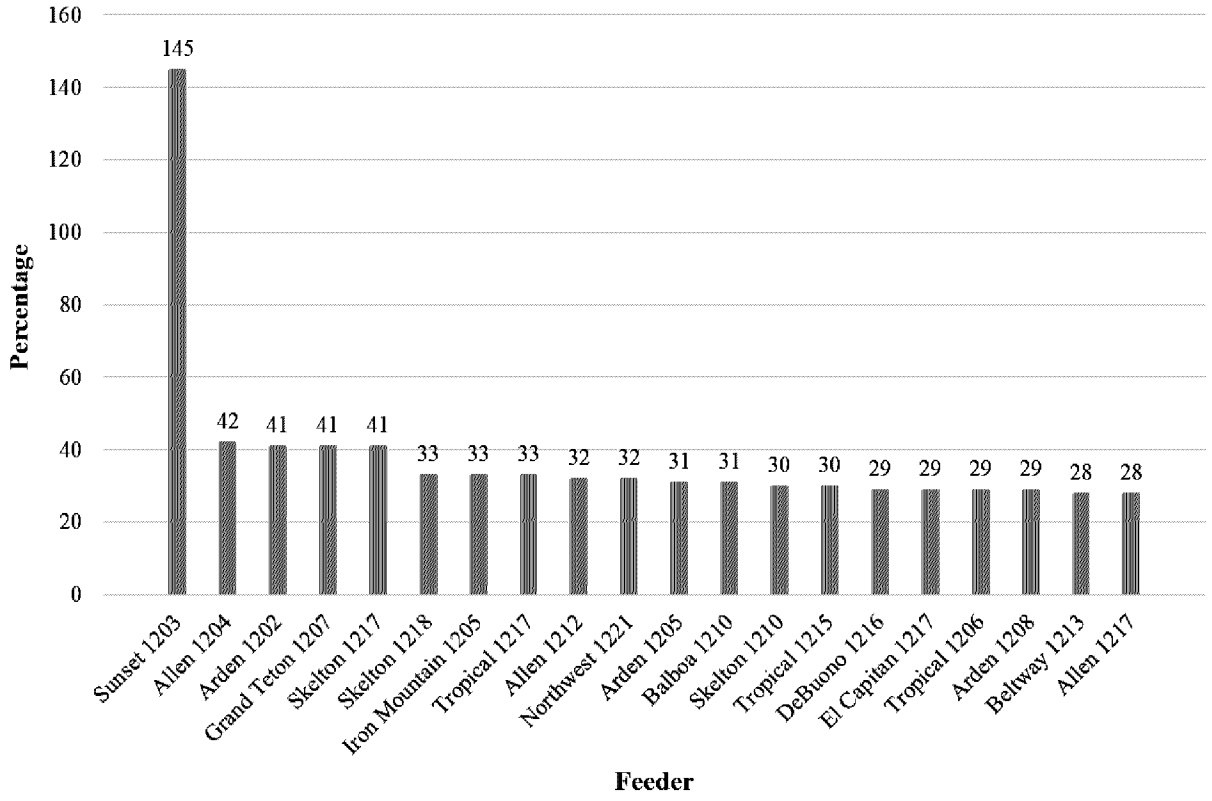
Company	NEM Resource (kW)				
	Solar	Wind	Hydro	Geothermal	Total
Nevada Power	750,661	29	0	0	**750,690**
Sierra	89,790	10,481	158	50	**100,479**
NV Energy	840,452	10,510	158	50	**851,170**

[13] Figure based upon data from monthly information provided by NV Energy's Renewables department as of June 30, 2023.

[14] Data taken from monthly information provided by NV Energy's Renewables department as of June 30, 2023. Totals for each of the Companies and NV Energy may be reflective of round-off error due to rounding of values to whole numbers.

While an overall penetration level over seven percent on the NV Energy distribution system as a whole does not approach the level of other states like California or Hawaii, similar to load growth, the localized nature of distribution-level constraints requires a more granular view of these installed DG assets to ascertain if clustering is occurring and local system issues could develop. NV Energy developed a DER Analytics Dashboard[15] to track these installations on a local level. DRP Update-Figures 3 and 4 below show the 20 distribution feeders with the highest percentage of DG penetration[16] on the Nevada Power and Sierra systems, respectively. DRP Update-Figures 5 and 6 below show the 20 distribution feeders with the highest total rated DG capacity installed and pending on the Nevada Power and Sierra systems, respectively. All of the figures reflect data as of May 31, 2023.

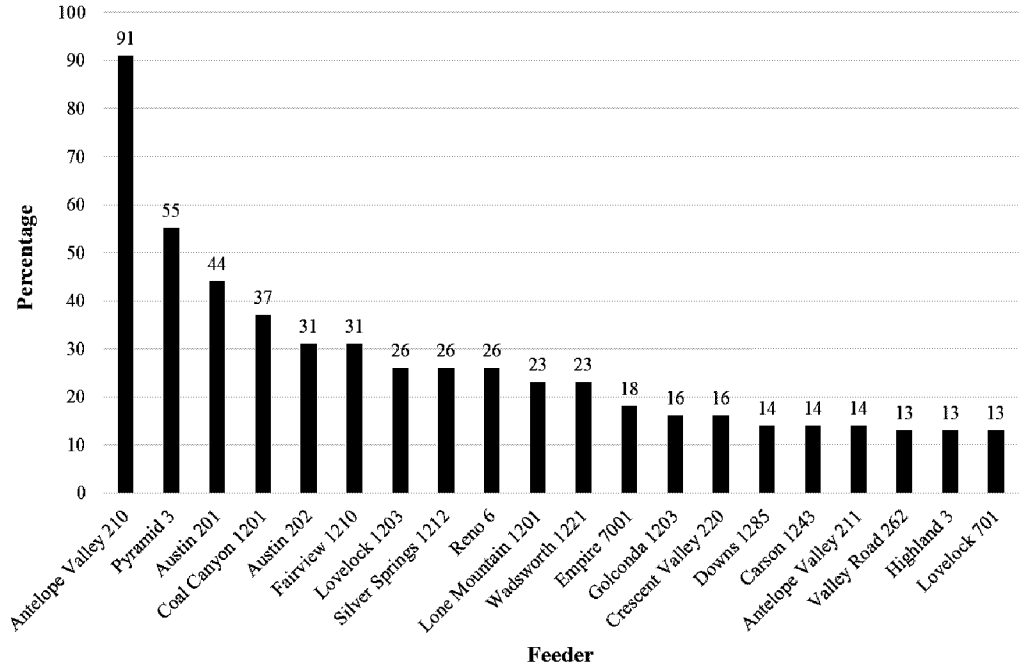
DRP UPDATE-FIGURE 3:
NEVADA POWER 20 HIGHEST PERCENTAGE DG PENETRATION FEEDERS



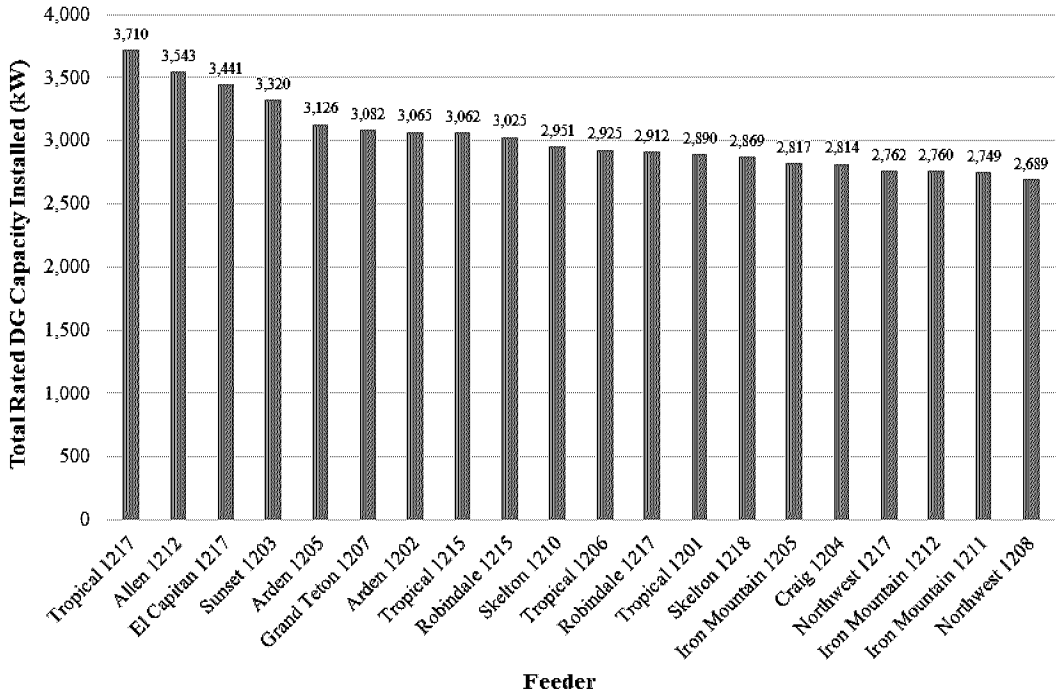
[15] Refer to NV Energy's 2019 DRP filing in Docket No. 19-04003, Section 9.B at 112-13.

[16] Percentage DG penetration is defined as the total rated DG capacity installed on a feeder divided by the most recent net peak loading on the feeder.

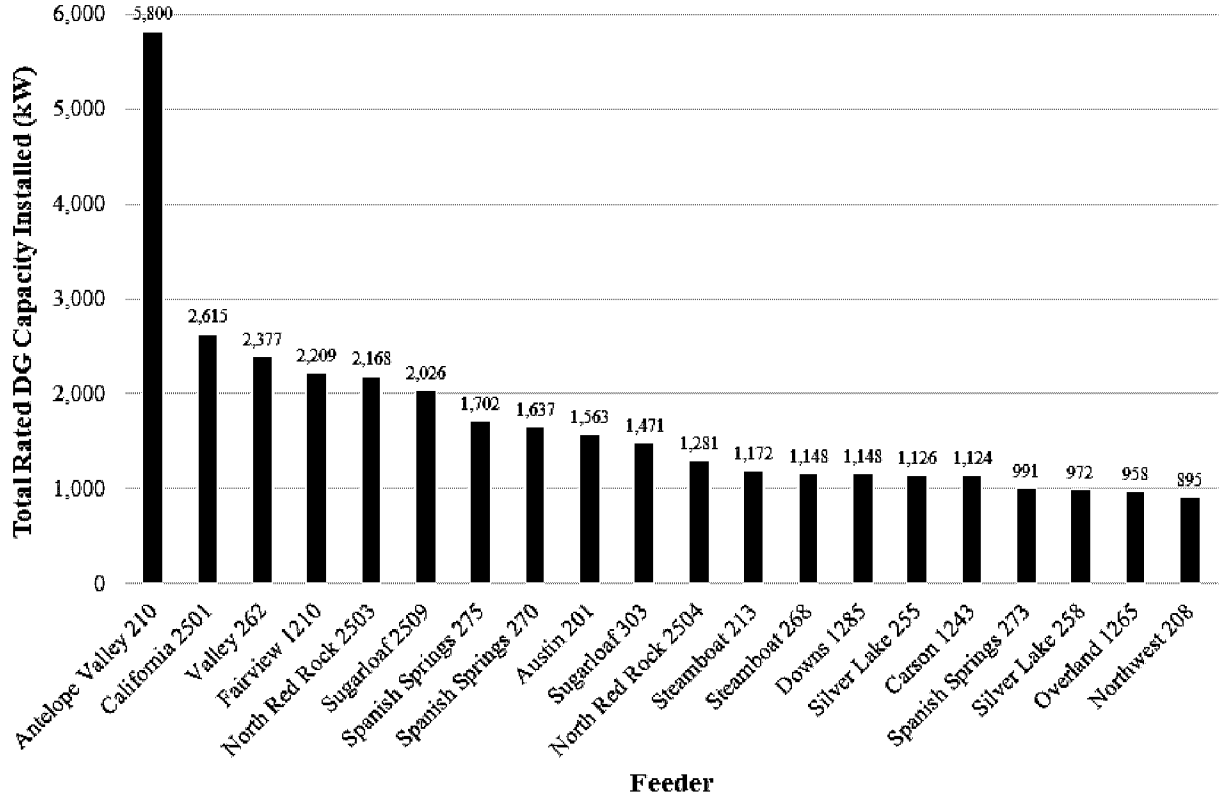
DRP UPDATE-FIGURE 4:
SIERRA 20 HIGHEST PERCENTAGE DG PENETRATION FEEDERS



DRP UPDATE-FIGURE 5:
NEVADA POWER 20 HIGHEST TOTAL RATED DG CAPACITY INSTALLED FEEDERS



DRP UPDATE-FIGURE 6:
SIERRA 20 HIGHEST TOTAL RATED DG CAPACITY INSTALLED FEEDERS



Since the denominator in the percentage DG penetration data in DRP Update-Figures 3 and 4 is actually the net peak loading on the feeder rather than the gross (or total) peak load, the data presents an imperfect picture of the penetration because the net peak loading includes the effect of the generation on the feeder, which may notably lower that loading for higher penetrated feeders. However, the purpose of tracking this data is to provide information about where DG is being installed on the distribution system to act as a gauge in directing attention to areas and feeders that may be increasing in and/or have comparatively higher installed DG capacity.

Of note in DRP Update-Figures 3 and 4 is that the Sunset 1203 and Antelope Valley 210 feeders are notably higher penetrated as compared to other feeders in the Nevada Power and Sierra service territories, respectively. The Sunset 1203 feeder is a relatively new feeder but serves residential development with solar PV as a standard part of the home offerings in the area, and so it has a high amount of DG capacity installed on it (note that it is the fourth feeder listed in DRP Update-Figure 5). Its peak loading is forecasted to increase significantly over the next few years, which will tend to decrease its penetration percentage, unless that load comes with DG on it as well. This feeder exhibits the situation explained in the previous paragraph where a high penetration of DG capacity is causing the net peak loading on the feeder to be notably reduced, resulting in a penetration percentage calculation over 100. The Antelope Valley 210 feeder had been discussed in NV

Energy's 2021 DRP filing[17] and currently does not present any operational issues on the distribution system.

F. Definitions and Acronyms

ADMS – Advanced Distribution Management System

AMI – Advanced Metering Infrastructure

ANSI – American National Standards Institute

BTM – Behind-the-meter

DERMS – Distributed Energy Resource Management System

Distributed Energy Resources (DERs) – Distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies, which can be in front of or behind the meter. Within this DRP Update, this term is used interchangeably with the term Distributed Resources as defined in NAC 704.90583 and the two terms have the same meaning.

DG – Distributed Generation

DR – Demand Response

DRMS – Demand Response Management System

DSM – Demand Side Management

EE – Energy Efficiency

EPRI – Electric Power Research Institute

ESD – Energy Storage Device

EV – Electric Vehicle

Feeder (*i.e.*, Circuit) – A medium-voltage (*e.g.*, 4 kV, 12 kV or 25 kV) line, either overhead or underground, that provides service from a substation transformer to a low-voltage electric system or directly to the customer.

FTM – Front-of-the-meter

[17] Refer to Docket No. 21-06001, Volume 13, p. 27 of 311.

GIS – Geographic Information System

Grid Needs Assessment (GNA) – A summary that includes the constraints on a utility's electric grid and solutions to those constraints. It includes all analysis of non-wires alternatives' suitability to mitigate identified constraints, results of locational net benefit analysis and recommendations for the deployment of utility infrastructure upgrade solutions and non-wires alternative solutions to identified constraints.

Hosting Capacity Analysis (HCA) – The analysis to determine the amount of distributed resources that can be accommodated on a particular feeder section of the distribution system at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

IEEE – Institute of Electrical and Electronics Engineers

IEEE Standard 1547 – The IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces. The 2003 version of this standard was updated in 2018.

kV – Kilovolt

kVA – Kilovolt-ampere

kVAR – Kilovolt-ampere reactive

kW – Kilowatt

kWh – Kilowatt-hour

Locational Net Benefit Analysis (LNBA) – A cost-benefit of Distributed Resources that incorporates the location-specific net benefits to the electric grid.

Model Forge – The process that pulls data from NV Energy's GIS mapping system into a Microsoft ("MS") Access database with the appropriate schema required by the Synergi Electric software.

MVA – Megavolt-ampere

MW – Megawatt

MWh – Megawatt-hour

Non-Wires Alternative (NWA) – A solution to an identified constraint(s) on a utility's electric grid that may include the deployment of a Distributed Resource or suite (portfolio) of Distributed Resources.

OMAG – Operation, Maintenance, Administrative, and General expense.

PI – Plant Information system from OSIsoft.

PV – Photovoltaic

"Real-time" Hosting Capacity Analysis – For the purposes of this DRP, updating hosting capacity values (1) on a monthly basis within a reasonable time after the utility determines that a parameter has changed that would appreciably affect a feeder section's hosting capacity value; and (2) within a reasonable time, but no more than a month, after a specific Distributed Energy Resource interconnection applicant of sufficient capacity has submitted an application to the utility that would appreciably affect a feeder section's hosting capacity value. This term is not defined in Nevada statute, regulation, or Commission order.

RNI – Regional Network Interface.

Substation – Location at which one or more substation transformers step down power from a transmission voltage to a distribution voltage.

T&D – Transmission and Distribution

Thermal Rating – The maximum amount of electrical current that an electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements. This is one of the limiting categories in the HCA.

TOU – Time-of-Use

V - Volt

Volt-VAR Optimization/Conservation Voltage Reduction (VVO/CVR) – An operational approach in which voltage- and VAR-controlling devices at the substation and on the distribution system work in concert to manage the voltage on the system within defined limits, specifically, to flatten the voltage profile along the distribution feeder so that the operating voltage can be lowered to achieve peak load, energy consumption, or loss reduction.

Section 3. Distributed Resources Plan Analyses

A. Distribution Planning and Integrated Grid Planning

NV Energy's Distribution Planning department provides support to both the Nevada Power and Sierra electric distribution systems. The Distribution Planning department has a twofold responsibility. First, the department is responsible for determining the distribution system construction requirements to economically and reliably accommodate load additions to the distribution system. Second, the department ensures that these load additions do not detrimentally affect the existing system and service to existing customers.

The department's major tasks include:

- Determining the distribution service requirements for distribution load additions;
- Recommending distribution capital improvement projects;
- Producing short-, mid-, and long-range distribution facility (feeder and medium-power substation transformer) load forecasts;
- Developing short-, mid-, and long-range distribution master plans; and
- Developing distribution power flow system models.

Formed in 2016, NV Energy's Integrated Grid Planning department also provides support to both the Nevada Power and Sierra electric distribution systems, but focuses on performing analyses related to the interconnection, impact, and facilitation of DERs on the electric distribution system. The term "integrated" refers both to the integration of DERs on the system and to ensuring coordinated planning efforts amongst the many departments at NV Energy that play increasing roles in utilizing DERs to deliver cost-effective and reliable services to NV Energy's customers.

The department's major tasks include:

- Performing DER interconnection review and Interconnection Studies;
- Compiling the GNA for distribution constraints;
- Performing HCA and other DER-related studies;
- Performing NWA analysis and LNBA for distribution constraints; and
- Investigating and supporting smart grid technology.

1. Load and DER Forecasting

a. Distribution Load Forecasting

NV Energy has a rigorous process for forecasting electric load growth on its distribution feeders and medium-power substation transformers. The Distribution Planning department generates short-term distribution facility (transformer and feeder) load forecasts for five years, which are mainly driven by applicant-submitted service requests on the electric distribution system. The proposed load additions are assigned to a specific distribution feeder(s), given an estimated in-service date based upon the requested date in the applicant's project information sheet, and an estimated time frame for the proposed load to fully come on line on the system (ramp-up period). Each feeder in Distribution Planning's internal database system is assigned to a substation transformer, and thus a substation transformer-level forecast is also generated. The substation transformer and distribution feeder forecasts serve as the main drivers for the determination of service requirements for applicants' service requests and proposal of traditional wired capital improvement projects generated from the department.

Distribution Planning considers all the following pieces of information when generating its distribution facility load forecasts:

- Historical distribution facility peak loading, normalized for temperature, and adjusted for abnormal switching;
- Reserved load values reflective of service requirements memos (planning memos) that have been written to reserve capacity on distribution facilities in association with applicants' service requests;
- Planned switching in association with applicants' service requests, capital improvement projects, or for other reasons; and
- Ramp-up periods based upon information provided in applicants' service requests and experience.

Forecasts for distribution feeders and substation transformers are generated to cover a 10-year timeframe to support corporate capital planning. However, given the uncertainty in forecasting at such a local level that far out in time, the latter five or six years of the 10-year forecast horizon are extremely variable, and experience supports a lower confidence level in their accuracy.

In this manner, distribution load forecasting at NV Energy is accomplished at a local level and aggregated up to the substation level, rather than based upon a system-level load forecast that is disaggregated down to a regional level, and then substation and feeder levels, which is a technique used at some other utilities.

No specific or new distribution facility load forecasts were produced for this DRP Update because the load forecasts for substation transformers and distribution feeders are continually updated by NV Energy's Distribution Planning department. A "snapshot" of the forecasts on specific dates in June 2023 served as the basis for the NWA analyses within the GNA and covered the required minimum six-year timeframe following the year of the filing of this DRP Update. Past peak loads from 2018 through 2022 on NV Energy's substation transformers and feeders are provided in **Technical Appendix DRP Update-2**. Forecasted peak loads as of July 17, 2023, for 2023 through 2029 on NV Energy's substation transformers and feeders are provided in **Technical Appendix DRP Update-3**.[18]

b. Distributed Energy Resources' Effect on Distribution Load Forecasting

NV Energy provided a report entitled "Effects of Net Metering Private Solar Photovoltaic Distributed Generation and Demand Response on Feeder Peak Loading" in its 2021 DRP filing in Docket No. 21-06001 as Technical Appendix DRP-3 in Volume 14 of that filing. No further study of this issue has occurred since that filing, however, the Companies expect to reanalyze this issue in the future.

c. Distributed Energy Resources Forecasting

DER forecasting is presently performed by the NV Energy departments mainly responsible for the programs under which the variety of DER technologies are made available to customers (*i.e.*, mainly the demand side management and clean energy areas). Generally, DER forecasts are developed and presented at the system level for both Nevada Power and Sierra. Thus, a disaggregation process to the region, substation, distribution feeder, or feeder section levels is required to support much of the technical analysis in the DRP. This was specifically performed for private solar NEM PV in support of the HCA studies in Section 3.A.2 below. As noted below in Section 8.A, however, the Companies have received an updated EV forecast by census block and are working to utilize that forecast to allocate the load associated with existing and future EV charging to individual feeders.

The verification of historical distribution feeder and substation transformer peak loading and load forecasting processes do not specifically account for the effects of DER technologies,[19] but the

[18] The forecasted values in Technical Appendix DRP Update-3 may not match the forecasted values used in the NWA Screening Analysis Tool for certain distribution facilities since the distribution substation transformer and feeder forecasts are updated daily. For the analyses on the constraints in NV Energy's 2023 Capital Plan performed using the NWA Screening Analysis Tool, NV Energy used the latest distribution forecast information available when the NWA analyses were performed, which was in June 2023. The data in Technical Appendix DRP Update-3 represents a snapshot of the forecasts on July 17, 2023.

[19] Meaning that any existing effects are considered as embedded in the past peak loading values and specific adjustments in the forecasted values due to potentially increasing DER penetration are not yet made.

Companies are monitoring this issue and may adjust distribution facility forecasting techniques in the future if deemed necessary and appropriate.

DER Forecasting and Valuation

In previous DRP filings and again in this DRP Update (see Section 11.B below), NV Energy has identified a gap in its adherence to NAC 704.9237(2)(f) regarding the forecasting of all DER types and requested a waiver of the appropriate part of that regulation. The Commission has granted the requests thus far. As noted in the Companies' 2022 DRP Update in Docket No. 22-09001,[20] the Companies have moved to close this gap by developing the requirements for a DER Analytics Toolset ("Toolset") and Potential Study that will ensure that all DER types are forecasted, able to be used in the analyses for the DRP, and made available in the appropriate level of detail and timeframes to other NV Energy departments for their use, and will investigate DER benefits currently used in the industry.

In the course of developing the functional and technical requirements for the Toolset, the Companies recognized the dependent relationship between the resulting data from a Market Potential Study ("MPS") of all DER types and DER forecasting and valuation, and so added requirements for a MPS to first be completed. The Companies issued a Request for Proposals ("RFP") entitled "DER Analytics Toolset and Potential Study" on March 24, 2023. **Technical Appendix DRP Update-4** provides the Scope of Work contained in the RFP. The Recommendation for Award was fully approved on May 22, 2023, and the contract was executed with the successful vendor, Integral Analytics, on July 27, 2023. The Companies have had initial meetings with the vendor and have begun work on the effort.

As noted below in Section 8.A, this effort is targeted for completion in the 2024 timeframe so that forecasts can be provided to support the 2024 DRP that is to be filed on or before June 1, 2024, as part of the Companies' 2024 Joint IRP.

2. Hosting Capacity Analysis

Generally, the hosting capacity of a distribution feeder is a measure of its ability to accommodate DER capacity before a technical, operational, or safety limitation is reached. It is then used in several ways:

- As shown on NV Energy's publicly-accessible DRP web portal, the results of the HCA provide information guiding customers, DER providers, and vendors to locations on the distribution system where additional DER capacity might be installed without potentially incurring distribution system upgrade costs;

[20] *See* Joint Application, Vol. 1 at 37 of 283.

- The output of the HCA is presently used in Supplemental Review in the DER interconnection process, but ultimately could replace or add to one of the Initial Review technical screens in the Companies' distribution interconnection Rule 15; and
- As an input to the GNA process, the HCA results could add another criterion by which constraints on the distribution system can be identified. Constraints identified on the basis of limited local hosting capacity in an area with verifiable DER capacity growth and the requisite traditional wired solutions to those constraints could feed into the GNA, similar to how traditional thermal, voltage, or reliability criteria are already relied upon to identify constraints.

The HCA studies performed by NV Energy utilize two systems. DNV's Synergi Electric electrical simulation software ("Synergi") is used to model and analyze the Companies' electric distribution systems. The electrical connectivity models of the distribution systems from NV Energy's Geographic Information System ("GIS") mapping system are used as the source for the connectivity models in Synergi.

Following NV Energy's 2021 DRP filing, the Companies performed a full-system HCA study process including all non-excluded feeders in the first quarter of 2022 modeling forecasted 2021–2029 conditions on the distribution system and again in the first quarter of 2023 modeling forecasted 2022-2030 conditions. The general study processes are described below, followed by information specific to the more recent full-system study.

A. Substation and Feeder Model Preparation

The process by which the components of the distribution system (*e.g.*, cables, conductors, transformers, fuses, switches, regulators, capacitors, reclosers, meters, dead-ends, pull boxes) and the connectivity model of the distribution system are populated from NV Energy's GIS mapping system into Synergi is referred to as the Model Forge process. The Model Forge process pulls data, which includes GIS and existing DG data on feeder sections, from a custom database in the GIS mapping system into a MS Access database with the appropriate schema required by Synergi. Several scripts[21] are then run to perform a model clean-up process which allows the GIS mapping elements and distribution equipment unique to NV Energy's system to be properly used by Synergi (*e.g.*, construction types, conductor or cable type/size, specific switch or fuse types/sizes, and proper connectivity of laterals), and any missing data to be flagged and filled in.

Synergi requires three main data source files to build a complete model: a feeder model, a substation model, and an equipment warehouse. Once these files were loaded, the clean-up scripts were run. To perform the HCA analyses for this filing, the preparation of NV Energy's distribution system models for use in Synergi required several clean-up scripts to be run to ensure proper

[21] Scripts are programs that automate the execution of tasks which alternatively would be executed one-by-one by a user of the software.

functioning of the Synergi software, among them, ones to: fix any loops detected, fix unfed sections, correct substation data, correct the naming of substation transformers, and select demand profiles.

Following this, Synergi contains a feature that allows the user to preview any remaining errors that may cause an unsuccessful load flow run. This "view info panel" was accessed and either gave an indication that the model was valid or provided warnings and error details. These were corrected prior to running the model.

Additionally, Synergi requires the peak loading of the feeders to be provided to provide the reference for the feeder loading profile data (*i.e.*, what value of load is 100 percent). Historical peak load readings data and forecasted feeder peak data provided by NV Energy's Distribution Planning Department were imported into the Synergi model.

NV Energy's current DER growth forecast is provided for both Nevada Power and Sierra's respective territories. A program was created to calculate the percentage growth for each territory and increase the nameplate rating of all existing DERs in the model by that percentage for all future model years.

One final model preparation step was to adjust the settings in Synergi for the distribution line capacitors so that they operated on the basis of 124 V high voltage and 118 V low voltage settings. These settings determined whether the capacitors were modeled as being energized (*i.e.*, "turned on") or not during the initial load allocation process in Synergi and the subsequent HCA studies. For example, if a voltage of 117 V was calculated in Synergi at the location of a distribution line capacitor, that capacitor was modeled as "on" since it was on a section that was under 118 V, which would then aid in increasing the voltage on the feeder during the load flow analysis.

b. Feeder Loading Profile Data Preparation

One of the main inputs that Synergi requires to run a time-series analysis is loading profile information for the modeled distribution feeders. In Synergi, the data in these loading profiles are in the form of a percentage of the peak loading on the feeder (noted above).

NV Energy acquired information from several sources to develop the feeder loading profile data used in the HCA studies. The general process for creating the necessary data was:

- First, loading data for the previous year were acquired for distribution feeders with metering data in the PI system. Generally, this consisted of kW and kVAR data. The data used represented an hourly average based upon the 5 to 10-second load read data available in PI.[22] Invariably, not all the loading data for all feeders represented normal or accurate

[22] Generally, older Remote Terminal Units ("RTUs") in NV Energy's substations provided 10-second telemetry data, while newer RTUs provided 5-second data.

telemetry. Some "0" values, repeated data values, or data gaps were encountered. For 0 data values, these were adjusted to the last known "good" value in the data set before the 0 value. Where these issues involved six hours or less of data, linear interpolation was used to replace the 0 or repeated values to create loading values more in line with what should be expected in the load profile for those hours. When more than six hours of suspicious data was flagged, further analysis was performed. In this manner, the loading profile data for every feeder was examined for outlying values that were likely the result of outages or abnormal switching, and corrections were made so that abnormal values were not selected for the HCA maximum or minimum loading. If a month of missing data was found, then that month's loading data, or load profile, from the current year or the prior year was used to fill in the missing data.

- Next, where feeder or substation transformer loading data was absent in PI, data from NV Energy's installed intelligent line sensors was acquired to attempt to fill in gaps. The sensor data mainly consisted of current (in amps), phase angle, and voltage information, as available. Typical sensor data consisted of 15-minute average readings. Due to the technical limitations of different sensor types, some sensors recorded information all year long, some only in the summer months, some only when communication issues did not create data gaps in the sensor data, and some did not record data every 15 minutes. Consequently, a few programs were written to develop the available sensor data for use in the feeder loading profiles. Depending upon the available sensor data, an average hourly reading was produced based upon anywhere from one to four readings for the hour. In some cases, one or two of the phases had readings, but the other phase had missing information. In these cases, an attempt was made to approximate the missing phase information based on the available phases. As with the available PI data, if previous year sensor data was missing, then an attempt was made to acquire current year sensor data or the prior year for the same time period to help fill in the feeder loading profile data gaps.

- Next, if loading data did not exist in PI for a selected feeder and there was no intelligent line sensor data available to utilize, then loading data for the substation transformer from which the feeder was served was acquired to attempt to create the feeder loading profile. This transformer loading data was scaled to the peak loading of the feeder in question to approximate the feeder loading profile. As required, the loading profile of the substation transformer data was used to establish the loading profile for the missing feeder loading data.

- If all the above techniques to acquire or develop accurate feeder loading data did not produce complete results or there simply was no available data from a feeder, substation transformer, or intelligent line sensor to draw from, then generic loading profiles for commercial, residential, or mixed feeders were used. Ten feeders within each category were selected from both the Nevada Power and Sierra territories that had good data and

an average loading profile was created for each feeder type (resulting in a total of six profiles; three for Nevada Power and three for Sierra). This generic loading profile was then used for the feeder loading profile.

- Finally, a 12-month view of the feeder loading profile was graphed to visually inspect the profile to identify any remaining errors in the data.

The above feeder loading profile data preparation process involved a great deal of effort to acquire data from several sources, manage the inconsistencies of the data, and fill in data gaps. However, techniques were developed over the course of the process which expedited the development of feeder loading profile.[23] The result of the feeder loading profile data preparation process was that the data for the entire year was used to determine the 24-hour loading on the peak and minimum loading days in each month of the year (*i.e.*, 24 loading data points for the highest load (peak) day and 24 loading data points for the lowest load (minimum) day for each month, resulting in 48 data points for each month, or 576 data points each for both kW and kVAR for the whole year). Since the data was for both kW and kVAR, these 576 x 2 loading data points were provided to Synergi to complete the information required to run time-series analysis.

c. HCA Study Analytical Method

NV Energy utilized Synergi's Incremental HCA and recipe files capabilities to perform the HCA for this filing. The recipe file is a text file that gives a sequence of commands for Synergi to follow. Macros were developed (originally by DNV and later modified by NV Energy) to create the recipe files. A recipe file allows multiple analyses to be automated and carried out sequentially by Synergi. This improves the efficiency of the analysis process as the user is no longer required to repeat the same process for each portion of the system to be analyzed. The Incremental HCA tool calculates the limiting criteria on each feeder section being modeled for all defined analysis hours and considers existing generation in calculating this limit. The result is the additional amount of capacity that could be added to each section in addition to existing DG without exceeding one of the technical criteria.

Incremental HCA uses a calculation approach. This allows results to be produced in a practical timeframe. What this means is that Synergi runs a baseline load flow analysis and then, using calculations based on impedances in the system, calculates the different limits. Synergi models the electric distribution system in sections. Thus, the HCA was run for each section in the Synergi models, thereby producing the most granular result possible. Distributed Resource capacity is set at 100 percent for the HCA generation calculations, and OFF for the load capacity calculations.

[23] For reference, Technical Appendix DRP-3 in NV Energy's April 2019 DRP filing in Docket No. 19-04003 contained a flowchart diagram of the above-described process for developing the feeder loading profile data.

NV Energy's approach to determining the hosting capacity of its distribution feeder sections included the following scenarios:

- Uniform Generation – This analysis case was designed to simulate the effects of DG on the distribution feeder sections, meaning, any DER technology that provides energy into the distribution system. Technologies could include inverter-based generation like solar PV, wind, and the discharging of BESS, or traditional distributed diesel generators. Simulating this case as uniform generation across the analysis timeframe accounts for the potential myriad of actual future scenarios where DERs could be generating (or discharging) at a variety of levels and times throughout the day or year, which presently cannot be determined with any certainty. The results of this analysis case are termed the Generation Hosting Capacity ("GHC").
- Uniform Load – This analysis case was designed to simulate the effects of additional load being imposed on the distribution feeder sections, meaning, any DER technology that is load-modifying. Technologies could include the charging of BESS, the charging of EVs, or the effects of DR programs. Essentially, this case reflected what traditional Distribution Planning load studies might endeavor to determine regarding the limitations of the distribution system in response to load growth. Simulating this case as uniform load across the analysis timeframe accounts for the potential myriad of actual future scenarios where DERs could simultaneously be charging and load modifying programs could be interacting with each other in a manner that presently cannot be determined with any certainty. The results of this analysis case are termed the Load Hosting Capacity ("LHC").
- Solar PV – This analysis case was designed to simulate the effects of solar PV being added to the distribution feeder sections. Although solar PV output varies throughout the daylight hours, the analysis assumed a constant output of the solar PV at rated capacity across the hours of 10:00 a.m. through 4:00 p.m. The logic for this assumption is that it is possible that solar PV output could be at its full rated capacity any time within these hours. NV Energy's opinion is that this assumption represents an acceptably conservative level of planning. By running the analysis at full output (instead of using irradiance curves, for example), it can be ensured that no practical limits should need to be placed on solar PV operation and that results are valid for any level of output up to full rated output. The results of this analysis case are termed the Photovoltaic Hosting Capacity ("PHC").

The HCA studies utilized the following criteria to determine technical limitations:

- Steady-State Voltage – A limitation was imposed for steady-state voltage on the distribution feeder sections with limits established as a maximum of 126 V and a minimum

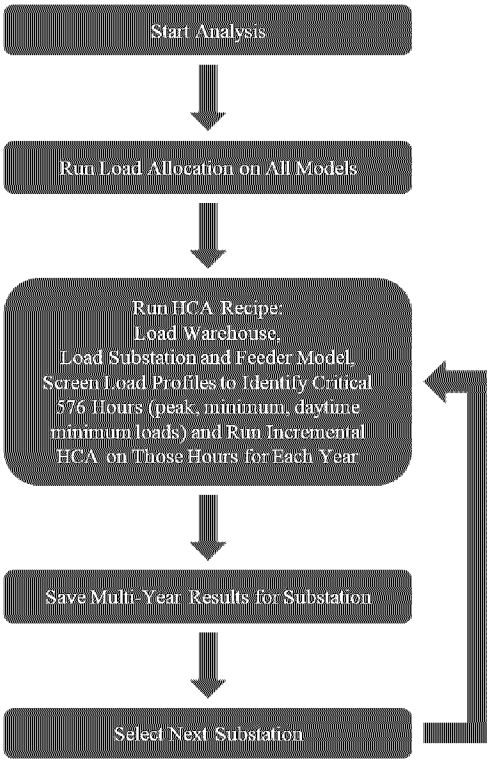
of 116 V[24] in line with the American National Standards Institute ("ANSI") Standard C84.1 Range A limits.

- Voltage Variation – A 3 V limitation was imposed for steady-state voltage to vary from its initial level to its final level either due to the addition or removal of DG capacity or load. This limitation was not meant to simulate or reflect transient voltage fluctuations or harmonics.
- Thermal Loading – A limitation was imposed when the normal continuous thermal ratings of the equipment modeled on the distribution feeders was reached in the simulations.
- Reverse Power Flow (Feeder) – A limitation was imposed that there must be no reverse power flow at the feeder breaker at the substation (and no thermal limits can be exceeded; the reverse power flow limit value is the lower of the two). However, this analysis was for informational purposes only with a view towards future HCA studies where system protection-related limiting criteria might be considered and was not used as a limiting criterion in the HCA studies for this filing.

DRP Update-Figure 7 below provides a high-level view of the process, including part of the model preparation process.

[24] Voltages are on a 120 V base. ANSI Standard C84.1 Range A voltage allows a minimum of 114 V at the customer's service entrance, but since the Companies' distribution systems are modeled in Synergi down to the primary voltage side of the service transformers only (*i.e.,* the service transformer itself and the secondary/service cable to the customer's meter is not modeled), an allowance for additional voltage drop between that point and the service entrance of 2 V was assumed.

DRP UPDATE-FIGURE 7:
HIGH-LEVEL HCA MODEL PREPARATION AND PROCESS



To help more efficiently run the HCA studies, a recipe was created that directed Synergi to perform the desired HCA scenarios, which substation transformers and feeders to analyze, and what technical criteria to use to establish limitations. A recipe provides the sequence of commands for Synergi to set up and execute the required analysis and report results and ensures that, when analyses are performed by multiple users, they are performed consistently, and the results files have identical structures. For any given HCA run, the feeders and substation transformers that were to be part of the run, the electronic folder to which the results were to be written, and any other required scripts were added to the recipe. The recipe includes a settings file which ensured that the same settings were used for all the HCA runs. The recipe then ran the substation and feeder models for a selected transformer, ran load allocation,[25] ran incremental HCA, saved the results file in MS Access format, moved to the next year, and, when every year was completed, then moved to the next transformer.

To reduce analytical time in Synergi, the NV Energy distribution system was separated into eight regions: three for Sierra and five for Nevada Power. Most often, the recipe was set to run an entire

[25] Load allocation is the process by which Synergi allocates the given maximum (peak) loading at the head-end of the feeder down to the sections of the feeder on which loads are modeled. This is accomplished via a weighted disaggregation of the peak loading based on the capacity ratings of the service transformers.

region of substations and feeders, but sometimes running certain substations and feeders within a region produced results more quickly. Depending upon how many sections were modeled for each feeder and substation[26] that were part of any individual HCA run, the analysis and production of results took anywhere from a few days to just over a week to complete.

In several instances, the HCA run did not progress, stopping on a particular substation transformer or simply producing results that did not include a transformer(s) that should have been part of the run. In these instances, either the run was terminated and investigated, or the cause of the missing transformers was investigated in the model. When corrections were found to be necessary, they were made and the run was either re-started or a new run of just the missing transformers was performed.

D. HCA Study Results

The HCA results files generated from Synergi were saved in MS Access format and contain the following pertinent information for each feeder section:

- Region of NV Energy's service territory;
- Substation Name;
- Substation Transformer ID;
- Feeder ID;
- (Feeder) Section ID;
- Analysis Year;
- Season (Month);
- Day Type (peak day, minimum load day);
- Hour of Day (1 to 24);
- Maximum Generation (MW) (the maximum Generation Hosting Capacity based upon all the criteria, including reverse power flow);
- Maximum Load (MW) (the maximum Load Hosting Capacity based upon the thermal and minimum voltage criteria);
- Maximum Generation Hosting Capacity based upon steady-state maximum voltage criterion (MW);

[26] The GIS mapping model of the Nevada Power distribution system contained over 1.1 million sections, or an average of approximately 1,200 sections per feeder. The model of the Sierra distribution system contained over 500,000 sections, or an average of approximately 1,400 sections per feeder.

- Maximum Generation Hosting Capacity based upon the delta voltage (voltage variation) criteria (MW);
- Maximum Generation Hosting Capacity based upon the thermal criterion (MW);
- Maximum Generation Hosting Capacity based upon reverse power flow criteria (MW);
- Maximum Generation Hosting Capacity based upon the steady-state minimum voltage criterion (MW);
- Load Hosting Capacity based upon the steady-state minimum voltage criterion (MW); and
- Load Hosting Capacity based upon the thermal criterion (MW).

When the MS Access results files were completed for an HCA run, the results were checked via a program that NV Energy created to identify anomalous results, for example: zeros, voltage or thermal issues that created a limitation, if a hosting capacity limitation occurred during a non-peak daytime hour, or not during summer or winter. In this manner, additional errors were found and corrected, and the HCA was re-run. Ultimately, the results were posted to an internal site for quality control review prior to publication to the publicly-accessible DRP web portal (refer to Section 7).

NV Energy completed two full-system HCA studies between the 2021 DRP filing and this 2023 DRP Update filing, generating results for all eight regions in its service territory and posting verified results to the publicly-accessible DRP web portal as they became available. Given the sheer volume of data associated with the HCA results, it is impractical to provide the results in hard copy form or even to provide the multitude of generated electronic files. The DRP web portal presents the best opportunity for interested parties to view and download the results that are of interest to them. The HCA results are color-coded (red-amber-green) by feeder section on the web portal, which is accessible directly at https://drp.nvenergy.com (through Google Chrome and Microsoft Edge). For security and tracking purposes, users must register to access the results. Once on the HCA results screen, a user can click on feeder sections to reveal pop-up boxes containing the results information and download the results data files by year and substation transformer.

While results for the feeders served from specific substation transformers can be provided, the volume of data associated with the analysis performed on the totality of NV Energy's distribution system does not allow for the results to be provided in the form of a Technical Appendix to this DRP Update. However, clicking on the "Aggregate Data" link on the top right of the screen provides a pop-up box showing an annual high-level summary of the number and percentage of feeder sections with incremental hosting capacity values in the ranges shown on the web portal and by limiting criteria. A DRP Web Portal User Guide can be downloaded from the DRP web portal landing page that fully explains the capabilities of and data accessible on the web portal.

(1) 2022-2030 HCA Study Specifics and Results

This full-system study was completed at the beginning of April 2023, with the results for each year made available for public viewing and the results files made available for download via the DRP web portal. This study generally proceeded as described above, with the following improvements in the process from the previous full-system study:

- Improved modeling of primary metered loads through use of metered peak load and loading profiles;
- Improved efficiency of the initial model cleanup process;
- Incorporated more accurate substation transformer impedance data;
- Improved meter load profiles in Synergi by running the 576 analyses;
- Improved Synergi calculations by using a program to remove most of the wandering laterals in the model;
- Improved the efficiency of the programs checking the HCA results and transferring profiles into the models;
- Improved the model by turning off capacitors that were put in a temporary state over a year ago; and
- Improved efficiency in creating recipe files for HCA runs.

DRP Update-Table 3 below provides the system-wide aggregate HCA results for 2024 as of July 6, 2023, in terms of both the incremental hosting capacity values and limiting factors.

DRP UPDATE-TABLE 3:
AGGREGATE 2024 HCA RESULTS

Hosting Capacity Analysis Result values

	0 MW		0-1 MW		1-5 MW		>5 MW	
	Number of sections	% of overall sections	Number of sections	% of overall sections	Number of sections	% of overall sections	Number of sections	% of overall sections
GHC	71,342	7.12%	395,762	39.51%	437,884	43.72%	96,642	9.65%
LHC	253,818	25.34%	522,940	52.21%	194,501	19.42%	30,371	3.03%
PHC	60,304	6.02%	380,261	37.96%	459,598	45.89%	101,467	10.13%

Hosting Capacity Analysis Result Limiting factors

	Thermal		Steady-State Voltage		Voltage Variation		>No Limit(20MW)	
	Number of sections	% of overall sections	Number of sections	% of overall sections	Number of sections	% of overall sections	Number of sections	% of overall sections
GHC	702,729	70.16%	275,730	27.53%	16,449	1.64%	6,722	0.67%
LHC	939,105	93.76%	62,450	6.23%	0	00.00%	75	0.01%
PHC	738,919	73.77%	234,075	23.37%	21,607	2.16%	7,029	0.70%

e. Progress Toward "Real-time" Hosting Capacity

The concept of, NV Energy's interpretation of, and the stakeholder discussions surrounding "Real-time" HCA were outlined in the Companies' 2019 DRP filing. As explained in detail in Section 3.A.2.e of the Companies' 2021 DRP filing, NV Energy developed an analytical tool in MS Excel to acquire and analyze data to determine which feeders require updated HCA monthly. Since its introduction and initial use in July 2020, the tool has identified an average of approximately 140 distribution substation transformers and 456 distribution feeders each month, representing an approximate average of 35 percent of NV Energy's total distribution feeders, and the Companies have updated the HCA on those feeders monthly. The tool has not been altered since its introduction because it has served the process well and no compelling reason has surfaced to revise it.

In addition to the process of identifying feeders requiring updated hosting capacity, the process to accomplish this hosting capacity updating monthly is very complex and it takes the full month to complete each monthly update. NV Energy has outlined the process to accomplish the monthly HCA update in a flowchart depicted in **Technical Appendix DRP Update-5**.

DRP Update-Table 4 below provides the number of distribution facilities that have had their hosting capacity updated each month in the monthly process.

DRP UPDATE-TABLE 4:
NV ENERGY MONTHLY HCA UPDATE PROCESS
NUMBER OF FACILITIES UPDATED

Year	Month	Number of Substation Transformers	Number of Feeders	Approximate Percentage of Total Feeders*
2020	July	112	315	24
	August	70	219	17
	September	146	445	34
	October	191	574	44
	November	158	496	38
	December	86	249	19
2021	April	126	394	30
	May	92	306	24
	June	93	296	23
	July	119	388	30
	August	119	386	30
	September	117	377	29
	October	193	613	47
	November	146	470	36
	December	153	506	39
2022	April	177	599	46
	May	137	473	36
	June	162	559	43
	July	148	503	39
	August	149	512	39
	September	156	521	40
	October	193	646	50
	November	149	522	40
	December	176	572	44
2023	April	Unable to perform update due to IT security issue		
	May			
	June			
	July			
Approximate Average		**140**	**456**	**35**

* Based upon 1,300 feeders.

Prior to the planned April 2023 HCA monthly update process, an Information Technology ("IT")-related issue arose that did not allow that and the following month's updates to be performed. The Synergi software accesses data from and writes data to MS Access files through the use of a 2013 MS Access Runtime driver in order to run power flow analysis and provide results, including HCA. Microsoft announced that it no longer would be supporting the 2013 driver and consequently NV

Energy's IT security protocols were augmented to disallow use of that driver to preclude any potential cybersecurity vulnerabilities related to it. NV Energy contacted its Synergi supplier (DNV) to determine if a more recent driver could be used and DNV indicated that the 2013 (or earlier) driver was needed to run the software until the release of an updated version of the software planned by the end of 2023 that would alleviate the issue.[27] NV Energy's Integrated Grid Planning department was eventually able to obtain the necessary security exception and approval to temporarily use the 2013 Microsoft driver until mitigating conditions could be enacted (*e.g.*, running the Synergi software on machines with no access to the Internet) and once again began performing the monthly HCA update process in August 2023.

NV Energy continues to examine its monthly HCA update process for opportunities to streamline and automate the process and will make adjustments as needed as experience is gained and the results of the process are reviewed.

3. Grid Needs Assessment – 2023 Capital Plan

NV Energy's GNA encompasses the constraints on the Companies' electric grid that could potentially be mitigated by deployment of DERs, traditional and NWA solutions to those constraints, determination of NWAs' suitability to mitigate identified constraints, results of locational net benefit analyses, and recommendations for the deployment of utility infrastructure upgrade solutions and NWA solutions to identified constraints.

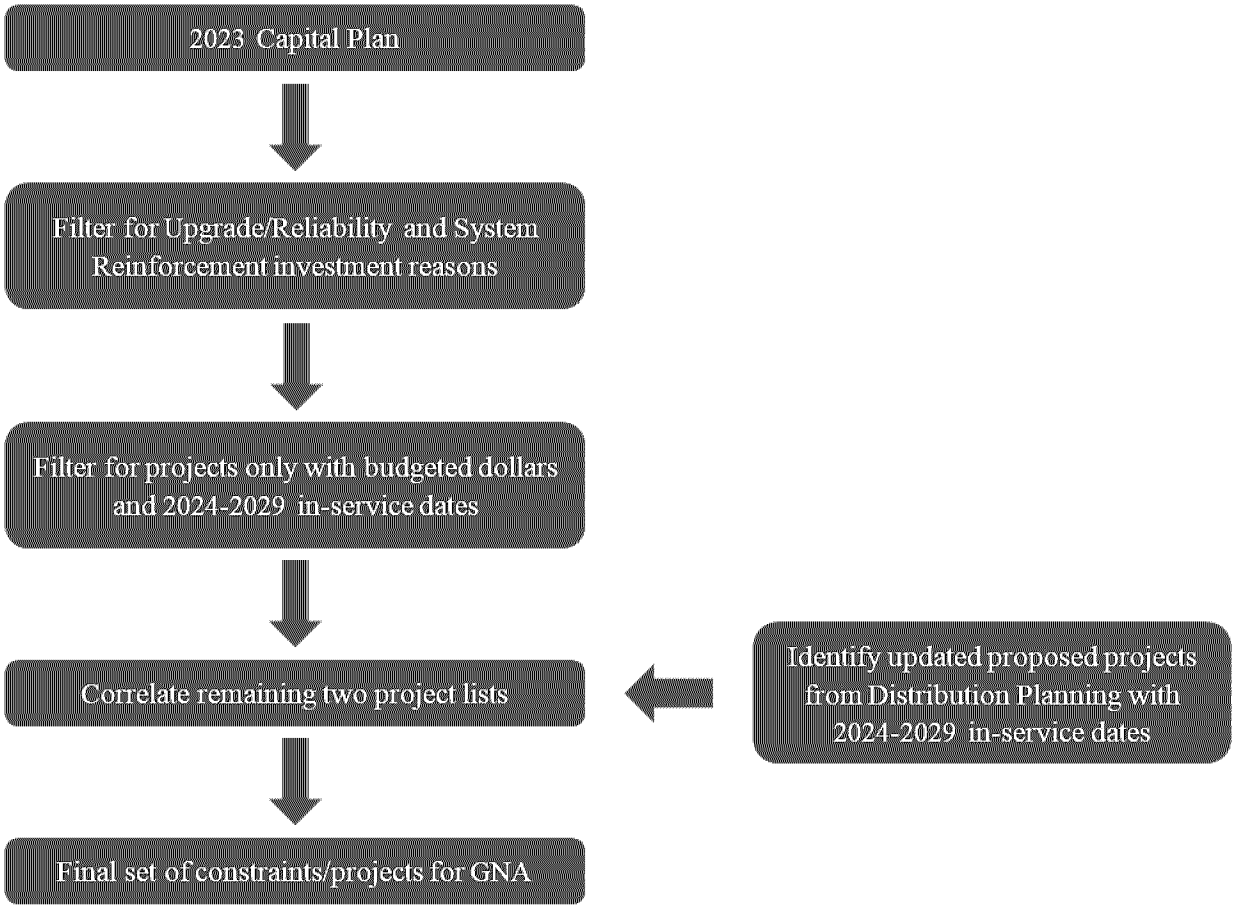
This 2023 DRP Update describes the GNA process that took place since the 2022 DRP Update filing based upon the Companies' 2023 Capital Plan (developed in late 2022).

a. Distribution Constraints and Projects Identification – 2023 Capital Plan

NV Energy utilized its 2023 Capital Plan as the source to identify what traditional capital upgrade projects the Companies plan to fund and complete in the coming years. This GNA includes constraints reflected in the Companies' 2023 Capital Plan, which are those that have been deemed as high enough priority or risk to mitigate through funding of a proposed traditional capital upgrade project. DRP-Figure 8 below depicts the high-level process that the Companies used to identify constraints for the GNA.

[27] The Synergi software is presently 32-bit and the updated Version 7 will be 64-bit, allowing use of the M365 driver to access the databases necessary to run the software.

DRP UPDATE-FIGURE 8:
2023 CAPITAL PLAN GNA CONSTRAINTS/PROJECTS IDENTIFICATION



Updated information from NV Energy's Distribution Planning department regarding proposed 2024-2029 projects was used to further refine the set of distribution system constraints.[28] The resulting final set of distribution constraints and traditional capital upgrade projects for the 2024-2029 timeframe included a total of 30 projects: 19 in the Nevada Power territory and 11 in the Sierra territory. The variety of forecasted constraints could include forecasted overloads of distribution substation transformer thermal ratings under normal operating conditions or under unplanned contingency conditions, forecasted loading above the current Standard Loading Criteria ("SLC") adopted for distribution facilities, and reliability-related constraints under unplanned contingency conditions.

[28] An initial download of information from Distribution Planning regarding proposed traditional distribution capital upgrade projects and their planned in-service dates was obtained on April 5, 2023. However, the analyses in the Non-Wires Alternatives Analysis – 2023 Capital Plan section below were not solely based upon this initial information. Updated information for each constraint was obtained on the date that the Non-Wires Alternative analysis was performed to capture any changes that may have occurred between April 5, 2023, and the date that the Non-Wires Alternative analyses were performed.

Since this 2023 DRP Update is applicable only to 2024, brief descriptions of the eight total constraint situations in that year (five in the Nevada Power territory and three in the Sierra territory) are provided below.

2024

Eight constraints on the Companies' distribution system were identified that are planned to be mitigated through traditional capital upgrade projects in 2024 (listed based upon in-service date first and alphabetical second):

- In the northeast region of the Las Vegas Valley, the existing paralleled 69/12 kV, 22.4 MVA transformers #1 and #2 at the Gypsum 138/69/12 kV Substation are forecasted to exceed both their combined normal thermal and SLC capacity ratings during 2024 summer peak loading conditions.

  Entitled "Gypsum 69/12 kV Bank 3 Addition [NE]," with an in-service date of January 1, 2024, the planned traditional capital upgrade project that will mitigate this constraint involves installing a second 69/12 kV, 22.4 MVA transformer and associated equipment at the substation.

- In the Truckee Meadows region northwest of Reno, the existing 120/25 kV, 46.7 MVA transformer #2 at the Northwest 120/25 kV Substation is forecasted to exceed both its normal thermal and SLC capacity ratings during 2024 summer peak loading conditions.

  Entitled "Northwest 120/25 kV Bank #2 Upgrade (Thermal N-0) [TM]," with an in-service date of May 31, 2024, the planned traditional capital upgrade project for mitigating this constraint involves replacing the existing transformer with a new 120/25 kV, 60 MVA transformer and associated equipment at the substation.

- In the southern part of the Las Vegas Valley, the existing paralleled 138/12 kV, 37 MVA transformers #1 and #2 at the 138/12 kV Bicentennial Substation are forecasted to exceed both their combined normal thermal and SLC capacity ratings during 2024 summer peak loading conditions.

  Entitled "Bicentennial Bank 3," with an in-service date of June 1, 2024, the planned traditional capital upgrade project that will mitigate this constraint involves installing a third 138/12 kV, 37 MVA transformer and associated equipment at the substation.

- In the southeast region of the Las Vegas Valley, the existing KHN 1210 feeder from the Keehn Substation is forecasted to exceed both its normal thermal capacity and SLC ratings during 2025 summer peak loading conditions.

  Entitled "Larson 1201 Feeder [SE]," with an in-service date of June 1, 2024, the planned traditional capital upgrade project that will mitigate this constraint involves installing a new feeder and associated equipment at the substation.

- In western Nevada, near the town of Gardnerville, the loading on the existing BUC 1276 feeder from the Buckeye Substation is forecasted to exceed its SLC capacity rating during 2024 summer peak loading conditions.

  Entitled "Pinenut 1252/1253 Tie (Thermal N-0)[CAR]," with an in-service date of June 1, 2024, the planned traditional capital upgrade project that will mitigate this constraint involves installing a tie between two feeders at the Pinenut Substation which will allow the transfer of existing load that will thereby allow loading relief of the BUC 1276 feeder.

- In the northeast region of the Las Vegas Valley, the existing 138x69/12 kV, 37 MVA transformers #1 and #2 at the Speedway 138/12 kV Substation are forecasted to exceed both their combined normal thermal capacity and SLC ratings during 2024 summer peak loading conditions.

  Entitled "Speedway 138x69/12 kV Bank 3 [NE]," with an in-service date of June 1, 2024, the planned traditional capital upgrade project that will mitigate this constraint involves installing a third 138x69/12 kV, 37 MVA transformer and associated equipment at the substation.

- In the southwest region of the Las Vegas Valley, the existing paralleled 138/12 kV, 37 MVA transformers #2 and #3 at the Tomsik 138/12 kV Substation are forecasted to exceed both their combined normal thermal and SLC capacity ratings during 2024 summer peak loading conditions.

  Entitled "Tomsik 138/12 kV Bank #1 [SW]," with an in-service date of June 1, 2024, the planned traditional capital upgrade project that will mitigate this constraint involves installing a third 138/12 kV, 37 MVA transformer and associated equipment at the substation.

- On the northeast side of Lake Tahoe in western Nevada, the load on the existing 120/14.4 kV, 28 MVA transformer #1 at the Incline 120/14.4 kV Substation exceeds the loading limit imposed by NV Energy's SLC during winter peak loading conditions. In 2018, imminent failure of the existing 120/14.4 kV, 33.6 MVA transformer was expected, and that transformer was removed and replaced with the now-existing 28 MVA transformer.

  Entitled "Incline #2 TFMR ADDN (Thermal N-0) [NTAH]," with an in-service date of September 1, 2024, the planned traditional capital upgrade project for mitigating this constraint involves installing a second 120/14.4 kV, 33.6 MVA transformer and associated equipment at the substation.

DRP Update-Table 5 below summarizes the pertinent information for each constraint. The data shown is for the year 2029 as this is the ending year of the analysis period. The table is broken into several graphics for ease of viewing, with Columns A through E repeated for identification purposes. The first graphic shows the identifying information, the second shows the deficiency

information, and the third shows the traditional capital upgrade project information for each situation.

DRP UPDATE-TABLE 5:
2023 CAPITAL PLAN GNA
SUMMARY FORECASTED DISTRIBUTION CONSTRAINT AND TRADITIONAL CAPITAL UPGRADE SOLUTIONS TABLE

A	B	C	D	E	F	G	H	I
Year	Company	Region	Substation	Facility ID	Facility Type	Constraint Type	Operational Condition	Seasonal Identification (Peak, Off-Peak, All)
2024	NPC	NPC-NE	Gypsum	GYP BK 2	Transformer	Thermal	Normal	Summer Peak
2024	SPPC	SPPC-TM	Northwest	NOW BK 2	Transformer	Thermal	Normal	Summer Peak
2024	NPC	NPC-SE	Bicentennial	BCT BK 1//2	Transformer	Thermal	Normal	Summer Peak
2024	NPC	NPC-SE	Keehn	KHN 1210	Feeder	Thermal	Normal	Summer Peak
2024	SPPC	SPPC-NW	Buckeye	BUC 1276	Feeder	Thermal	Normal	Summer Peak
2024	NPC	NPC-NE	Speedway	SPD BK 1//2	Transformer	Thermal	Normal	Summer Peak
2024	NPC	NPC-SW	Tomsik	TOM BK 2//3	Transformer	Thermal	Normal	Summer Peak
2024	SPPC	SPPC-NW	Incline	INC BK 1	Transformer	Reliability	Unplanned Contingency	Winter Peak

A	B	C	D	E	J	K	L	M	N	O	P	Q
Year	Company	Region	Substation	Facility ID	Total Estimated Duration of Deficiency in 2029	Total Estimated Days of Deficiency in 2029	Estimated Duration of Deficiency on Peak Day in 2029	Deficiency Start Time on Peak Day in 2029	Deficiency End Time on Peak Day in 2029	Criteria (Ratings)	Initial Deficiency	Estimated Maximum Deficiency in 2029
2024	NPC	NPC-NE	Gypsum	GYP BK 2	1,266.75 hours	163 days	9.00 hours	5:15 AM	2:15 PM	40,320 kVA	12,060 kVA	36,790 kVA
2024	SPPC	SPPC-TM	Northwest	NOW BK 2	18.25 hours	4 days	4.25 hours	4:00 PM	8:15 PM	42,030 kVA	1,723 kVA	5,533 kVA
2024	NPC	NPC-SE	Bicentennial	BCT BK 1//2	403.75 hours	63 days	10.25 hours	1:00 PM	11:15 PM	66,600 kVA	10,017 kVA	29,292 kVA
2024	NPC	NPC-SE	Keehn	KHN 1210	1,643.75 hours	142 days	21.25 hours	6:45 AM	4:00 AM	11,650 kVA	2,633 kVA	8,938 kVA
2024	SPPC	SPPC-NW	Buckeye	BUC 1276	31.50 hours	13 days	5.25 hours	2:15 PM	7:30 PM	10,690 kVA	718 kVA	1,804 kVA
2024	NPC	NPC-NE	Speedway	SPD BK 1//2	3,094.50 hours	176 days	24.00 hours	12:00 AM	12:00 AM	66,600 kVA	12,383 kVA	36,529 kVA
2024	NPC	NPC-SW	Tomsik	TOM BK 2//3	830.50 hours	104 days	13.00 hours	11:00 AM	12:00 AM	66,600 kVA	9,962 kVA	41,175 kVA
2024	SPPC	SPPC-NW	Incline	INC BK 1	117.75 hours	10 days	23.50 hours	12:15 AM	11:45 PM	25,200 kVA	6,403 kVA	9,088 kVA

A	B	C	D	E	R	S	T
Year	Company	Region	Substation	Facility ID	T&D Infrastructure Upgrade Project Name	Estimated Cost	T&D Infrastructure Upgrade Reserve Margin in 2029
2024	NPC	NPC-NE	Gypsum	GYP BK 2	Gypsum 69/12 kV Bank 3 Addition [NE]	$1,720,533	0 kVA
2024	SPPC	SPPC-TM	Northwest	NOW BK 2	Northwest 120/25 kV Bank #2 Upgrade (Thermal N-0) [TM]	$4,968,664	12,437 kVA
2024	NPC	NPC-SE	Bicentennial	BCT BK 1//2	Bicentennial Bank 3	$2,232,599	4,180kVA
2024	NPC	NPC-SE	Keehn	KHN 1210	Larson 1201 Feeder [SE]	$4,527,706	2,712 kVA
2024	SPPC	SPPC-NW	Buckeye	BUC 1276	Pinenut 1252/1253 Tie (Thermal N-0) [CAR]	$404,733	0 kVA
2024	NPC	NPC-NE	Speedway	SPD BK 1//2	Speedway 138X69/12 KV Bank 3 [NE]	$3,257,277	0 kVA
2024	NPC	NPC-SW	Tomsik	TOM BK 2//3	Tomsik 138/12 kV Bank #1 [SW]	$2,488,322	0 kVA
2024	SPPC	SPPC-NW	Incline	INC BK 1	Incline #2 TFMR ADDN (Thermal N-0) [NTAH]	$13,178,782	18,912 kVA

The columns in DRP Update-Table 5 above are explained below:

- Column A: Year – The year in which the constraint is forecasted to occur.
- Column B: Company – The territory in which the constraint is forecasted to occur; either Sierra ("SPPC") or Nevada Power ("NPC").
- Column C: Region – The region within each company's territory in which the constraint is forecasted to occur. There are five regions designated in the Nevada Power territory: NVE-NE (Northeast), NVE-NW (Northwest), NVE-SE (Southeast), NVE-SW (Southwest), and NVE-Strip (Las Vegas Strip area). There are three regions designated in the Sierra territory: SPPC-TM (Truckee Meadows), SPPC-NE (Northeast), and SPPC-NW (Northwest).
- Column D: Substation – The name of the substation in which the constrained distribution system facility is located or is served from.
- Column E: Facility ID – The unique identifier for the constrained distribution system facility, which begins with either a two- or three-character abbreviation for the substation, the abbreviation "BK" if the facility is a substation transformer, and a number identifying either the position of the substation transformer in the substation or the feeder breaker number if the facility is a distribution feeder. The symbol "//" means that two substation transformers are normally operated in parallel with each other.
- Column F: Facility Type – The type of constrained distribution facility, *e.g.*, substation transformer or feeder.
- Column G: Constraint Type – The type of constraint, including, reliability, thermal, or voltage.
- Column H: Operational Condition – The operating condition in which the constraint occurs, including, normal operating, unplanned contingency, or planned abnormal conditions (*e.g.*, during scheduled maintenance or construction).

- Column I: Seasonal Identification – Identifies the season of the year in which the constraint mainly occurs, including, Peak (generally, June through September), Off-Peak (generally, October through May), or All (occurs almost throughout the year). This is subjectively based the Total Estimated Duration of Deficiency in 2029 and the Total Estimated Days of Deficiency in 2029.

- Column J: Total Estimated Duration of Deficiency in 2029 – Based upon forecasted annual 15-minute load curve information, this is the estimated total number of hours in the year 2029 that the forecasted loading will be above the established limit (*i.e.*, there will be a deficiency). The year 2029 is chosen for this and other parameters as it is the last year in the six-year timeframe from the year of this filing and the last year covered by the GNA.

- Column K: Total Estimated Days of Deficiency in 2029 – Based upon forecasted annual 15-minute load curve information, this is the estimated total number of days in the year 2029 that the forecasted loading will be above the established limit at any time during the day.

- Column L: Estimated Duration of Deficiency on Peak Day in 2029 – Based upon forecasted annual 15-minute load curve information, this is the estimated total number of hours on the forecasted peak load day in the year 2029 that the forecasted loading will be above the established limit.

- Column M: Deficiency Start Time on Peak Day in 2029 – Based upon forecasted annual 15-minute load curve information, this is the time of the day on the forecasted peak load day in the year 2029 that the forecasted loading will begin to be above the established limit.

- Column N: Deficiency End Time on Peak Day in 2029 – Based upon forecasted annual 15-minute load curve information, this is the time of the day on the forecasted peak load day in the year 2029 after which the forecasted loading will cease to be above the established limit.

- Column O: Criteria (Ratings) – This is the criteria used to establish the constraint (*i.e.*, the established limit). Most often, this is the normal continuous rating or the SLC rating of the distribution facility on which the constraint occurs.

- Column P: Initial Deficiency – In kW, this is the amount of the constraint as compared to the Criteria or Rating that either exists today or is forecasted to exist in the first year of the constraint.

- Column Q: Estimated Maximum Deficiency in 2029 – In kW, this is the amount of the constraint as compared to the Criteria or Rating that is forecasted to exist in 2029. In

comparison to the Initial Deficiency, this figure can help to gauge how the constraint may be increasing or decreasing over time.

- Column R: T&D Infrastructure Upgrade Project Name – The name of the approved traditional T&D capital upgrade project in the Companies' 2023 Capital Plan that is meant to address the constraint.

- Column S: Estimated Cost – The estimated cost in today's dollars for the approved traditional T&D capital upgrade project in the Companies' 2023 Capital Plan that is meant to address the constraint.

- Column T: T&D Infrastructure Upgrade Reserve Margin in 2029 – The estimated amount of incremental capacity that the traditional T&D capital upgrade project will install in 2029, above what is necessary to accommodate the Estimated Maximum Deficiency in 2029. This value is based only on a cursory calculation, not load flow analysis, and should be viewed only as a general comparative gauge between the constraint solutions.

Although the 2021 DRP was filed only about two years ago and the 2022 DRP Update a year ago, there was significant change in the in-service dates of the distribution traditional capital upgrade projects that were planned to be in-service in 2024 between the time of the filing of the 2021 DRP and this 2023 DRP Update mainly due to changes in the load forecast for the affected distribution system elements. DRP Update-Table 6 below summarizes these changes and illustrates the volatility of the distribution capital plan, even in the short-term.

DRP UPDATE-TABLE 6:
2024 DISTRIBUTION TRADITIONAL CAPITAL UPGRADE SOLUTIONS COMPARISON TABLE

Distribution Constraint/NWA	Current In-service Year	Company	June 2021 Filing (2024 ISD)	September 2022 Update Filing (2024 ISD)	September 2023 Update Filing (2024 ISD)	Comment
Bicentennial Bank 3	2024	Nevada Power		✓	✓	ISD moved from 2026 to 2024 after the June 2021 filing.
Grand Teton Bank 3	2026	Nevada Power		✓		ISD moved from 2031 to 2024 after the June 2021 filing, then moved to 2026 after the September 2022 filing.
Gypsum Bank 3	2024	Nevada Power			✓	ISD moved from 2035 to 2026 after the June 2021 filing, then moved to 2024. Not budgeted prior to the 2023 Capital Plan.
Incline #2 Transformer Addition	2024	Sierra	✓	✓	✓	Consistent ISD.
Larson 1201 Feeder	2024	Nevada Power		✓	✓	ISD moved from 2022 to 2024 after the June 2021 filing. Not budgeted prior to the 2022 Capital Plan.
MYS Bank 1	2025	Nevada Power		✓		ISD moved from 2023 to 2024 after the June 2021 filing, then moved to 2028, 2027, and finally 2025 after the September 2022 filing.
Northwest Bank #2 Upgrade	2024	Sierra		✓	✓	ISD moved from 2022 to 2024 after the June 2021 filing.
Peavine Substation	2025	Sierra		✓		ISD moved from 2023 to 2024 after the June 2021 filing, then moved to 2025 after the September 2022 filing.
Pinenut 1252/1253 Tie	2024	Sierra			✓	ISD moved from 2023 to 2024. Not budgeted prior to the 2023 Capital Plan.
Speedway Bank 3	2024	Nevada Power		✓	✓	ISD moved from 2028 to 2024 after the June 2021 filing.
Tomsik Bank 1	2024	Nevada Power			✓	ISD moved from 2023 to 2025 after the June 2021 filing, then moved to 2024 after finalization of the project list for the September 2022 filing.

b. Non-Wires Alternative Analysis – 2023 Capital Plan

As discussed above, an NWA is a solution to an identified constraint(s) on NV Energy's electric transmission or distribution systems that may include the deployment of one or more DERs in lieu of a traditional wired solution.

(1) NWA Suitability/Screening Criteria – 2023 Capital Plan

DERs have the potential for deferring, and in unique cases eliminating, the need for traditional infrastructure solutions. However, the services they provide do not always align with the needs or characteristics of existing or forecasted constraints on the utility electric system. Also, timing issues in the form of short lead times may make potential NWA solutions less viable. Consequently, NV Energy developed NWA Suitability/Screening Criteria ("Suitability Criteria") to filter planned traditional T&D capital upgrade projects and better identify those situations where an NWA solution would be a viable alternative to address an existing or forecasted constraint, and thus potentially defer a planned traditional wired T&D capital upgrade project. DRP Update-

Figure 9 below shows the updated NWA Suitability/Screening Criteria used when the constraints and capital upgrade projects in NV Energy's 2023 Capital Plan were examined.

DRP UPDATE-FIGURE 9:
2023 CAPITAL PLAN
NON-WIRES ALTERNATIVE SUITABILITY/SCREENING CRITERIA

Critical Suitability Criteria		Yes	No	Comment
A.	Is the constraint anticipated to occur between January 1, 2024 and December 31, 2029?			
B.	Is the constraint based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading or energy consumption, or load shifting, on the transmission or distribution facilities involved would eliminate or defer the constraint?			
	Perform Non-Wires Alternative Analysis?	**Yes**	**No**	(Highlight the response)
Yellow Flag Suitability Criteria				
C.	Is the wired solution still within the planning or design stage, with no major equipment on order, received, or installed?			
D.	Is it reasonable to assume at this time that local residents would accept a Distributed Energy Resources solution in this area?			
E.	Is it reasonable to assume at this time that local governmental agencies would accept a Distributed Energy Resources solution in this area?			
F.	Is it reasonable to assume at this time that there are no environmental concerns which would preclude a Distributed Energy Resources solution in this area?			
G.	Is it reasonable to assume at this time that a Distributed Energy Resources solution would be able to be physically sited in this area?			
1.	If both responses to the **Critical Suitability Criteria** A and B are Yes, then proceed with the Non-Wires Alternative analysis.			
2.	If either of the responses to **Critical Suitability Criteria** A or B are No, then provide appropriate comment(s) and do not proceed with the Non-Wires Alternative analysis.			
3.	The Yellow Flag Suitability Criteria are meant to identify possible impediments to the actual implementation of Non-Wires Alternative solutions. They are not used to determine whether or not a Non-Wires Alternative analysis should or should not be performed. The responses to the Yellow Flag Suitability Criteria can provide support to an ultimate decision to proceed with implementation of a Non-Wires Alternative solution or not. A NO response in any of the Yellow Flag Suitability Criteria does not automatically determine that a Non-Wires Alternative solution will not be implemented. NO responses should only be entered if there is good reason supported by prior knowledge or experience, or discussion with knowledgeable personnel. Document all discussions in the Comments area and via a separate attachment if necessary.			

The Suitability Criteria are divided into Critical and Yellow Flag sections. For the Critical section, there are two criteria:

- Criterion A addresses the issue of timing. NV Energy's NWA analyses for the 2023 Capital Plan included reviewing constraints and planned traditional wired T&D capital upgrade projects within the 2024-2029 timeframe (a minimum of six years beginning with the year after the 2023 DRP Update is being filed, although only 2024 analyses are included in this filing).
- Criterion B addresses the characteristics of an existing or forecasted constraint on the utility electric system. If the constraint relates to thermal overload, voltage, or reliability, where a reduction in peak demand or energy consumption, or a temporal shifting of load, would avoid or eliminate the constraint, an NWA technology could be utilized to address the issue.

For the Yellow Flag section, there are five criteria:

- Criterion C addresses the fact that certain near-term planned traditional wired T&D capital upgrade projects may already be well into their planning, design, or construction phases, with major equipment potentially either ordered, delivered, or installed, and significant capital funds spent. In these situations, it may be prudent to forgo further investigation of an NWA and continue with the installation of the wired solution.
- Criterion D addresses the fact that local residents have or may express opposition to the installation of certain NWA technologies based on their footprint or aesthetics, or simply that they are unfamiliar with or untrusting of the technology in comparison to the wired utility facilities that they are used to.
- Criterion E is similar to Criterion D but addresses the potential issues from the perspective of local governmental agencies rather than residents.
- Criterion F addresses the fact that certain areas may have restrictive environmental requirements that could delay or preclude the installation of certain DERs (*e.g.*, like wind or diesel generation).
- Criterion G addresses the fact that there may be physical limitations in citing certain NWA technologies in certain areas. For example, an NWA analysis may reveal that a solar PV and BESS solution may be a viable alternative to a traditional wired solution in a certain location, but land on which to cite the solution is not available. In practice, in the preliminary NWA analysis, NV Energy does not attempt to determine whether certain DER technologies could be sited in certain areas. A blanket assumption is made that any such issue would be addressed later should the results of an NWA analysis reveal that a DER solution may be recommended.

The questions in each of the Critical Suitability Criteria were posed so that if both of the responses were "Yes," then an NWA analysis should be conducted. If either of the two Critical Suitability Criteria were answered "No," then an NWA analysis should not be performed.

The Yellow Suitability Criteria do not determine whether an NWA analysis should be performed, but rather, address several practical considerations in the process of determining whether an NWA solution can and should be implemented. As noted in DRP Update-Figure 9, a "No" response to any of the Yellow Flag Criteria does not automatically determine that an NWA solution should not be implemented, but simply raises the issue involved.

(2) NWA Analysis Methods – 2023 Capital Plan

To perform the NWA analyses for this filing, NV Energy utilized an updated version of its MS Excel-based NWA Screening Analysis Tool.[29] This updated tool determines the estimated sizing and ballpark capital cost of potential alternative DER solutions to identified constraints and compares the PWRR of these solutions (including the deferred traditional wired capital upgrade solution) against the PWRR of the traditional wired capital upgrade solutions in the planned in-service year. Generally, the tool accomplishes the following:

- Captures information about the traditional wired capital upgrade solution;
- Provides the Suitability/Screening Criteria results;
- Provides aerial geographic information in the area of the constraint;
- Provides single-lines of the substations involved;
- Captures 15-minute load data for the constrained electric system facility;
- Provides outage data (only if necessary);
- Determines the amount of the constraint in future years (*i.e.*, the need) in terms of MVA, MWh, number of days over the established limit, and number of hours over the established limit on any day selected in the analysis (normally, the peak day);
- Allows multi-year determination of the estimated amounts of EE, DR, Volt-VAR Optimization/Conservation Voltage Reduction ("CVR"), solar PV, and BESS (including the effect of charging) DER technologies necessary to mitigate the constraint;
- Provides a ballpark capital cost estimate for the NWA DER portfolio based upon updated cost data for each technology; and
- Compares the ballpark estimated NWA DER portfolio solution plus deferred traditional wired capital upgrade option PWRR, including estimated benefits due to energy supply, generation capacity, and energy arbitrage, to the estimated PWRR of the traditional wired capital upgrade solution option in the planned in-service year.

Asset limits were established for all the constraint scenarios to determine the estimated magnitudes and lengths of the deficiencies in the forecast years. For constraints characterized by a forecasted thermal overload under normal operating conditions, the asset limits were determined based upon the normal continuous thermal ratings of the affected facilities. For constraints characterized by a forecasted thermal overload of NV Energy's established SLC limits for substation transformers

[29] This tool is a complex functioning model in MS Excel that cannot readily be provided as a Technical Appendix. NV Energy provided the NWA analyses performed with this tool in support of this filing as confidential executable electronic files part of its confidential workpapers in this filing. The Companies welcome the opportunity to demonstrate the updated version of this model to interested parties.

and distribution feeders, the asset limits were determined based upon the criteria provided in **Technical Appendix DRP Update-6**. NV Energy's SLC had previously only applied to Sierra, but it has been updated and now applies to both Companies. Where two distribution substation transformers exist at the substation and the constraint has been determined as occurring under the contingency of the loss of one of the transformers, the asset limit was determined based upon the rating of the remaining smaller-capacity transformer. Finally, where one distribution substation transformer exists at the substation and the constraint has been determined as occurring under the contingency of the loss of that transformer, the asset limit was generally determined to be 0 MVA.

The general process for determining the NWA portfolio of DER technologies as solutions to the forecasted constraints involved first determining the amount of existing DR capacity on the constrained electric facility and assuming that up to 27 percent[30] of that capacity could be utilized to additionally reduce the forecasted loading via a geo-targeted DR program developed specifically for the constrained facility at essentially no incremental cost. Next, the numbers of distribution substation transformers and feeders involved in the specific constraint were determined to establish the proper cost for the CVR technology. Finally, given that several DER technologies with different characteristics, costs, and potential benefits could be chosen in the tool, the MS Excel "Solver" function was used to help minimize the NWA portfolio solution PWRR, along with manual iteration of technology sizing and timing of DR event starting and CVR starting and stopping, if needed.

To present somewhat realistic limitations on the sizing of the various DER technologies that can be used in the preliminary NWA analyses, and to aid in driving a mix of the technologies in the NWA portfolio solutions, a maximum of 5 Mwac for solar PV and 2 percent potential loading reduction for incremental EE and CVR were used in the analyses. It is especially important to establish such limits considering that otherwise the single DER technology with the lowest cost would always be selected by the tool to satisfy the system constraint regardless of whether the necessary capacity of the technology involved or reduction amount could realistically be achieved in the area of the constraint.

When the BESS technology was used in the NWA DER portfolio, the charging required for the BESS was also modeled to ensure that the effect of increased loading due to the charging requirement would not exceed the asset limit in any hour of the day. Instances where this was the case were noted.

[30] This 27 percent figure is the difference between the approximate 90 percent reduction seen based upon the results of the two geo-targeted DR demonstrations projects at the Village Substation in 2019 and the Northwest Substation in 2020 and the approximate 63 percent reduction achievable via the normal DR program run each summer to reduce loading at the system level. An assumption being made is that the normal DR program was run the previous peak period on the day that the peak loading on the distribution facility was captured upon which the forecast for that facility was based. Therefore, a reduction from existing DR assets is already embedded in the past peak loading and forecast values for the facility, and a transition to a specific geo-targeted DR program for that facility would be able to achieve an additional 27 percent reduction.

As noted in the NWA Screening Analysis Tool, a cost of $1,074,000/Mwac for utility-scale solar PV was used, and costs of $236,000/MW and $255,000/MWh were used for the BESS.[31] Per MW costs for incremental EE and DR capacity were determined and provided by NV Energy's Demand Side Management department (specific to Nevada Power or Sierra), and costs for the expansion of CVR capacity were determined including hardware and licensing costs on a scaled basis depending upon how many distribution substation transformers and feeders were involved in the specific constraints.

In determining the PWRR for the NWA solution portfolio, the following assumptions were made:

- Ongoing operational expense of 2 percent of the estimated capital cost of the solution in the initial year with an annual escalation of 2 percent;
- Book Life of 10 years and a Tax Life of 5 years; and
- Energy (for solar PV only), generation capacity, and energy arbitrage (for BESS only) benefit values per marginal energy price forecasts, capacity price forecasts, and production cost data provided by NV Energy's Resource Planning department.

(3) NWA Analyses Discussion and Results – 2023 Capital Plan

2024 – Gypsum

The loading on the paralleled Gypsum transformers #1 and #2 is forecasted to exceed both the combined thermal and SLC ratings of 44.8 MVA and 40.32 MVA, respectively, under normal operating conditions by the summer peak of 2024. Loading information revealed a 2022 peak loading of 10.64 MVA, with about 87.22 MVA of load growth forecasted over the next 10 years. The NWA analysis was run with an asset limit (rating) of 40.32 MVA.

In this analysis, existing DR capacity was 0 kW because of an absence of existing DR capacity on the feeders served by the substation, and the solution portfolios did not utilize any additional incremental DR load reduction to achieve minimum PWRR solutions. Varying amounts of CVR capacity between 1,048 kW and 1,542 kW were used to reduce the forecasted loading, equivalent to the maximum of 2 percent loading reduction each year. Energy Efficiency capacity was only required in 2029 at 1,542 kW to achieve a minimum PWRR solution in that year. No solar PV capacity was used since the cost of this technology created a higher NWA solution portfolio PWRR as compared to portfolios without this technology. Finally, any remaining kW or kWh overload

[31] The cost for solar PV was taken from information in the National Renewable Energy Laboratory's ("NREL's") 2022 Annual Technology Baseline ("ATB") for Cost for Utility PV (moderate value), and the costs for BESS was taken from information in the NREL 2022 ATB for 2023 60 MW 240 MWh 4hr battery CAPEX (moderate value).

amounts were addressed via a BESS automatically sized each year by the NWA Screening Analysis Tool ranging from 11,012 kW to 33,706 kW and 13,389 kWh to 71,944 kWh.

DRP Update-Table 7 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wired solution deferral savings.

DRP UPDATE-TABLE 7:
GYPSUM 69/12 kV BANK 3 ADDITION
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	0.00	0.00	0.00	12:00:00 AM	1.05	0.00	11.01	13.39	$ 5,114,664	$ 243,649	($4,871,015)
2025	0.00	0.00	0.00	12:00:00 AM	1.21	0.00	18.84	28.66	$ 9,674,167	$ 340,404	($9,333,763)
2026	0.00	0.00	0.00	12:00:00 AM	1.26	0.00	21.32	33.81	$ 11,165,682	$ 431,826	($10,733,855)
2027	0.00	0.00	0.00	12:00:00 AM	1.27	0.00	21.69	34.62	$ 11,396,015	$ 518,208	($10,877,806)
2028	0.00	0.00	0.00	12:00:00 AM	1.40	0.00	28.48	51.20	$ 15,865,075	$ 599,830	($15,265,245)
2029	1.54	0.00	0.00	12:00:00 AM	1.54	0.00	33.71	71.94	$ 21,814,277	$ 676,953	($21,137,324)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

2024 – Northwest

The loading on the existing Northwest transformer #2 is forecasted to exceed both its thermal and SLC ratings of 46.7 MVA and 42.03 MVA, respectively, under normal operating conditions by the summer peak of 2024. Loading information revealed a 2022 peak loading of 41.7 MVA, with about 7.39 MVA of load growth forecasted over the next 10 years. The NWA analysis was run with an asset limit (rating) of 42.03 MVA.

In this analysis, 218 kW of the existing installed DR capacity was used in the NWA solution portfolio under the assumption of a geo-targeted DR program being developed and implemented and providing incremental load reduction. Additional incremental DR reduction capacity of 1,000 kW was used in the NWA solution portfolios for all analysis years. Varying amounts of EE capacity between 906 kW and 951 kW were used to reduce the forecasted loading, except for 2024 and 2025. No solar PV capacity was used since the cost of this technology created a higher NWA solution portfolio PWRR as compared to portfolios without this technology. No incremental CVR capacity was used for the same reason. Finally, any remaining kW or kWh overload amounts were addressed via a BESS automatically sized each year by the NWA Screening Analysis Tool ranging from 963 kW to 3,851 kW and 787 kWh to 8,838 kWh.

DRP Update-Table 8 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wires solution deferral savings.

DRP UPDATE-TABLE 8:
NORTHWEST 120/25 kV BANK #2 UPGRADE
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	0.00	0.22	1.00	5:30:00 PM	0.00	0.00	0.96	0.79	$ 598,725	$ 637,924	$39,200
2025	0.00	0.22	1.00	5:15:00 PM	0.00	0.00	1.75	2.28	$ 1,049,279	$ 868,793	($180,487)
2026	0.91	0.22	1.00	5:15:00 PM	0.00	0.00	1.61	1.98	$ 1,479,258	$ 1,089,595	($389,664)
2027	0.92	0.22	1.00	5:00:00 PM	0.00	0.00	2.36	3.87	$ 1,988,413	$ 1,300,770	($687,643)
2028	0.94	0.22	1.00	5:00:00 PM	0.00	0.00	3.10	6.22	$ 2,565,495	$ 1,502,738	($1,062,757)
2029	0.95	0.22	1.00	5:00:00 PM	0.00	0.00	3.85	8.84	$ 3,184,710	$ 1,695,899	($1,488,811)

As reflected in the table, for 2024, the PWRR of the estimated costs, as adjusted for benefits, of an NWA portfolio solution sized to address the forecasted overload in that year was slightly less than the PWRRs savings of deferring the wired capital upgrade project. Therefore, the results of the screening analysis supported further consideration of an NWA portfolio solution sized to defer the wired capital upgrade project to 2025. This situation is discussed further in the next section.

2024 – Bicentennial

The loading on the existing paralleled Bicentennial transformers #1 and #2 is forecasted to exceed both their combined thermal and SLC ratings of 74.0 MVA and 66.6 MVA, respectively, under normal operating conditions by the summer peak of 2024. Loading information revealed a 2022 peak loading of 66.55 MVA, with about 40.87 MVA of load growth forecasted over the next 10 years. The NWA analysis was run with an asset limit (rating) of 66.6 MVA.

In this analysis, about 907 kW of the existing installed DR capacity was used in the NWA solution portfolio under the assumption of a geo-targeted DR program being developed and implemented and providing incremental load reduction. Varying amounts of additional incremental DR load reduction were included in the NWA solution portfolios ranging from 163 kW to the maximum of 1,000 kW. Varying amounts of CVR capacity between 1,532 kW and 1,918 kW were used to reduce the forecasted loading, equivalent to the maximum of 2 percent loading reduction each year. Similarly, varying amounts of EE capacity between 1,532 kW and 1,918 kW were used to reduce the forecasted loading, up to the maximum of 2 percent loading reduction in those years. No solar PV capacity was used since the cost of this technology created a higher NWA solution portfolio PWRR as compared to portfolios without this technology. Finally, any remaining kW or kWh overload amounts were addressed via a BESS automatically sized each year by the NWA Screening Analysis Tool ranging from 5,983 kW to 25,456 kW and 15,381 kWh to 137,301 kWh.

DRP Update-Table 9 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wires solution deferral savings.

DRP UPDATE-TABLE 9:
BICENTENNIAL BANK 3
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	1.53	0.91	0.16	5:30:00 PM	1.53	0.00	5.98	15.38	$ 4,658,047	$ 324,468	($4,333,579)
2025	1.61	0.91	0.11	5:30:00 PM	1.61	0.00	9.75	35.34	$ 9,005,786	$ 453,535	($8,552,251)
2026	1.69	0.91	0.34	6:45:00 PM	1.69	0.00	14.60	58.40	$ 14,256,992	$ 575,489	($13,681,502)
2027	1.76	0.91	1.00	7:00:00 PM	1.76	0.00	18.08	80.82	$ 19,990,160	$ 690,721	($19,299,438)
2028	1.84	0.91	1.00	7:15:00 PM	1.84	0.00	21.77	108.02	$ 26,757,639	$ 799,602	($25,958,037)
2029	1.92	0.91	1.00	7:45:00 PM	1.92	0.00	25.46	137.30	$ 34,071,227	$ 902,482	($33,168,745)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

2024 – Larson

The loading on the Keehn 1210 feeder is forecasted to exceed both its thermal and SLC ratings of 12.94 MVA and 11.65 MVA, respectively, under normal operating conditions by the summer peak of 2024. Loading information revealed a 2022 peak loading of 11.18 MVA, with about 13.25 MVA of load growth forecasted over the next 10 years. The NWA analysis was run with an asset limit (rating) of 11.65 MVA.

In this analysis, about 107 kW of the existing installed DR capacity was used in the NWA solution portfolio under the assumption of a geo-targeted DR program being developed and implemented and providing incremental load reduction. Additional incremental DR reduction capacity of 1,000 kW was used in the NWA solution portfolios for all analysis years. Varying amounts of EE capacity and CVR capacity between 286 kW and 412 kW were used to reduce the forecasted loading, each equivalent to the maximum of 2 percent loading reduction for each technology each year. Varying amounts of solar PV capacity between 477 kW and 4,238 kW were used to reduce the forecasted loading in all analysis years except 2024. Finally, any remaining kW or kWh overload amounts were addressed via a BESS automatically sized each year by the NWA Screening Analysis Tool ranging from 1,730 kW to 7,719 kW and 6,858 kWh to 58,010 kWh.

DRP Update-Table 10 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wired solution deferral savings.

DRP UPDATE-TABLE 10:
LARSON 1201 FEEDER
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	0.29	0.11	1.00	3:00:00 PM	0.29	0.00	1.73	6.86	$ 2,012,895	$ 658,019	($1,354,876)
2025	0.32	0.11	1.00	2:00:00 PM	0.32	0.48	4.08	21.98	$ 6,147,102	$ 919,769	($5,227,333)
2026	0.35	0.11	1.00	9:00:00 PM	0.35	1.73	5.14	32.77	$ 9,964,644	$ 1,167,091	($8,797,553)
2027	0.36	0.11	1.00	9:00:00 PM	0.36	2.05	5.46	35.73	$ 10,988,301	$ 1,400,782	($9,587,519)
2028	0.39	0.11	1.00	9:00:00 PM	0.39	3.16	6.59	46.43	$ 14,644,129	$ 1,621,591	($13,022,538)
2029	0.41	0.11	1.00	9:00:00 PM	0.41	4.24	7.72	58.01	$ 18,509,062	$ 1,830,231	($15,678,831)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

2024 – Pinenut

The loading on the Buckeye 1276 feeder is forecasted to exceed its SLC thermal rating of 10.69 MVA, respectively, under normal operating conditions by the summer peak of 2024. Loading information revealed a 2022 peak loading of 10.79 MVA, with about 2.40 MVA of load growth forecasted over the next 10 years. The NWA analysis was run with an asset limit (rating) of 10.69 MVA.

In this analysis, about 78 kW of the existing installed DR capacity was used in the NWA solution portfolio under the assumption of a geo-targeted DR program being developed and implemented and providing incremental load reduction. Varying amounts of additional incremental DR reduction capacity between 288 kW and 1,000 kW were used in the NWA solution portfolios each year. Varying amounts of EE capacity between 237 kW and 250 kW were used to reduce the forecasted loading in the 2026 through 2029 analysis years. Varying amounts of CVR capacity between 228 kW and 250 kW were used to reduce the forecasted loading, equivalent to the maximum of 2 percent loading reduction each year. No solar PV capacity was used since the cost of this technology created a higher NWA solution portfolio PWRR as compared to portfolios without it. Finally, any remaining kW or kWh overload amounts were addressed via a BESS automatically sized each year by the NWA Screening Analysis Tool ranging from 269 kW to 658 kW and 120 kWh to 1,491 kWh.

DRP Update-Table 11 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wired solution deferral savings.

DRP UPDATE-TABLE 11:
PINENUT 1252/1253 TIE
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	0.00	0.08	0.29	3:45:00 PM	0.23	0.00	0.27	0.12	$ 207,509	$ 52,110	($155,399)
2025	0.00	0.08	0.62	3:45:00 PM	0.23	0.00	0.35	0.32	$ 353,105	$ 70,969	($282,136)
2026	0.24	0.08	0.51	3:45:00 PM	0.24	0.00	0.35	0.27	$ 448,514	$ 89,005	($359,508)
2027	0.24	0.08	0.77	3:45:00 PM	0.24	0.00	0.35	0.41	$ 548,775	$ 105,257	($442,518)
2028	0.25	0.08	1.00	3:45:00 PM	0.25	0.00	0.44	0.81	$ 700,372	$ 122,756	($577,616)
2029	0.25	0.08	1.00	3:45:00 PM	0.25	0.00	0.66	1.49	$ 871,701	$ 138,535	($733,167)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

2024 – Speedway

The loading on the paralleled Speedway transformers #1 and #2 is forecasted to exceed both their combined thermal and SLC ratings of 74.0 MVA and 66.6 MVA, respectively, under normal operating conditions by the summer peak of 2024. Loading information revealed a 2022 peak loading of 30.8 MVA, with about 93.73 MVA of load growth forecasted over the next 10 years. The NWA analysis was run with an asset limit (rating) of 66.6 MVA.

In this analysis, existing DR capacity was 0 kW because of an absence of existing DR capacity on the feeders served by the substation. However, additional incremental DR load reduction of the maximum of 1,000 kW was included in the NWA solution portfolios in all analysis years. Varying amounts of both EE capacity and CVR capacity between 1,580 kW and 2,063 kW were used to reduce the forecasted loading, equivalent to the maximum of 2 percent loading reduction for each technology for each year. Five-thousand kW of solar PV capacity was also used in all analysis years. Finally, any remaining kW or kWh overload amounts were addressed via a BESS automatically sized each year by the NWA Screening Analysis Tool ranging from 4,176 kW to 28,361 kW and 8,084 kWh to 348,108 kWh.

DRP Update-Table 12 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wired solution deferral savings.

DRP UPDATE-TABLE 12:
SPEEDWAY 138x69/12 kV BANK #3 ADDITION
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	1.58	0.00	1.00	10:15:00 AM	1.58	5.00	4.18	8.08	$ 7,729,716	$ 473,386	($7,256,330)
2025	1.75	0.00	1.00	7:15:00 AM	1.75	5.00	13.34	84.23	$ 25,923,748	$ 661,691	($25,262,057)
2026	1.76	0.00	1.00	7:15:00 AM	1.76	5.00	14.02	93.29	$ 28,234,795	$ 839,617	($27,395,178)
2027	1.78	0.00	1.00	7:30:00 PM	1.78	5.00	14.67	104.59	$ 31,142,210	$ 1,007,735	($30,134,474)
2028	1.92	0.00	1.00	9:00:00 PM	1.92	5.00	21.51	212.91	$ 58,920,359	$ 1,166,589	($57,753,770)
2029	2.06	0.00	1.00	9:00:00 PM	2.06	5.00	28.36	348.11	$ 93,774,271	$ 1,316,685	($92,457,585)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

2024 – Tomsik

The loading on the paralleled Tomsik transformers #2 and #3 is forecasted to exceed both their combined thermal and SLC ratings of 74.0 MVA and 66.6 MVA, respectively, under normal operating conditions by the summer peak of 2024. Loading information revealed a 2022 peak loading of 67.09 MVA, with about 62.67 MVA of load growth forecasted over the next 10 years. The NWA analysis was run with an asset limit (rating) of 66.6 MVA.

In this analysis, about 2,840 kW of the existing installed DR capacity was used in the NWA solution portfolio under the assumption of a geo-targeted DR program being developed and implemented and providing incremental load reduction. Additional incremental DR reduction capacity of 1,000 kW was used in the NWA solution portfolios for all analysis years, except 2025. Varying amounts of EE capacity and CVR capacity between 1,531 kW and 2,156 kW were used to reduce the forecasted loading, each equivalent to the maximum of 2 percent loading reduction for each technology each year. Varying amounts of solar PV capacity between 1,917 kW and 5,000 kW were used to reduce the forecasted loading in all analysis years except 2024 and 2025. Finally, any remaining kW or kWh overload amounts were addressed via a BESS automatically sized each year by the NWA Screening Analysis Tool ranging from 4,595 kW to 35,687 kW and 10,533 kWh to 229,155 kWh.

DRP Update-Table 13 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wired solution deferral savings.

DRP UPDATE-TABLE 13:
TOMSIK 138/12 kV BANK #1 ADDITION
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	1.53	2.84	1.00	4:45:00 PM	1.53	0.00	4.60	10.53	$ 3,304,683	$ 361,632	($2,943,051)
2025	1.69	2.84	0.45	6:00:00 PM	1.69	0.00	13.59	54.36	$ 12,921,742	$ 505,484	($12,416,258)
2026	1.80	2.84	1.00	6:45:00 PM	1.80	1.92	19.12	84.71	$ 22,148,565	$ 641,405	($21,507,158)
2027	1.86	2.84	1.00	7:15:00 PM	1.86	4.80	21.67	100.40	$ 28,509,651	$ 769,837	($27,739,814)
2028	2.01	2.84	1.00	8:00:00 PM	2.01	5.00	28.65	160.57	$ 43,780,364	$ 891,189	($42,889,175)
2029	2.16	2.84	1.00	8:45:00 PM	2.16	5.00	35.69	229.15	$ 61,085,326	$ 1,005,852	($60,079,474)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

2024 – Incline

The loading on the Incline transformer #1 exceeds its SLC rating of 25.2 MVA under normal operating conditions in the winter peak season. Loading information revealed a 2022 peak loading of 29.7 MVA,[32] with about 5.66 MVA of load growth forecasted over the next 10 years. The NWA analysis was run with an asset limit (rating) of 25.2 MVA.

In this analysis, about 21 kW of the existing installed DR capacity was used in the NWA solution portfolio under the assumption of a geo-targeted DR program being developed and implemented and providing incremental load reduction. Additional incremental DR reduction capacity of 1,000 kW was used in the NWA solution portfolios for all analysis years. Varying amounts of EE capacity and CVR capacity between 632 kW and 686 kW were used to reduce the forecasted loading, each equivalent to the maximum of 2 percent loading reduction for each technology each year. No solar PV capacity was used since the cost of this technology created a higher NWA solution portfolio PWRR as compared to portfolios without this technology. Finally, any remaining kW or kWh overload amounts were addressed via a BESS automatically sized each year by the NWA Screening Analysis Tool ranging from 5,139 kW to 7,716 kW and 40,713 kWh to 86,781 kWh.

DRP Update-Table 14 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wired solution deferral savings.

[32] Analysis of the transformer and the loading revealed that this loading level would not result in catastrophic failure of the transformer, but the condition should not be allowed to remain or worsen.

DRP UPDATE-TABLE 14:
INCLINE #2 TRANSFORMER ADDITION
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	0.63	0.02	1.00	9:00:00 PM	0.63	0.00	5.14	40.71	$ 10,837,680	$ 1,743,007	($9,094,672)
2025	0.64	0.02	1.00	9:00:00 PM	0.64	0.00	5.65	49.19	$ 13,042,294	$ 2,375,168	($10,667,126)
2026	0.65	0.02	1.00	9:00:00 PM	0.65	0.00	6.17	58.05	$ 15,347,576	$ 2,979,765	($12,367,811)
2027	0.66	0.02	1.00	9:00:00 PM	0.66	0.00	6.68	67.05	$ 17,692,486	$ 3,558,002	($14,134,485)
2028	0.67	0.02	1.00	9:00:00 PM	0.67	0.00	7.20	76.57	$ 20,172,570	$ 4,111,027	($16,061,542)
2029	0.69	0.02	1.00	9:00:00 PM	0.69	0.00	7.72	86.78	$ 22,837,405	$ 4,639,940	($18,197,455)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

DRP Update-Table 15 below summarizes the identifying information, NWA portfolio parameters, and traditional capital upgrade project information for each of the above constraints. The data shown is for the year 2029, as this is the ending year of the analysis period. The table is broken into several graphics for ease of viewing, with Columns A through E repeated for identification purposes.

DRP UPDATE-TABLE 15:
2023 CAPITAL PLAN
SUMMARY FORECASTED DISTRIBUTION CONSTRAINT AND NWA SOLUTIONS TABLE

A	B	C	D	E	F	G	H	I
Year	Company	Region	Substation	Facility ID	Facility Type	Constraint Type	Operational Condition	Seasonal Identification (Peak, Off-Peak, All)
2024	NPC	NPC-NE	Gypsum	GYP BK 2	Transformer	Thermal	Normal	Summer Peak
2024	SPPC	SPPC-TM	Northwest	NOW BK 2	Transformer	Thermal	Normal	Summer Peak
2024	NPC	NPC-SE	Bicentennial	BCT BK 1//2	Transformer	Thermal	Normal	Summer Peak
2024	NPC	NPC-SE	Keehn	KHN 1210	Feeder	Thermal	Normal	Summer Peak
2024	SPPC	SPPC-NW	Buckeye	BUC 1276	Feeder	Thermal	Normal	Summer Peak
2024	NPC	NPC-NE	Speedway	SPD BK 1//2	Transformer	Thermal	Normal	Summer Peak
2024	NPC	NPC-SW	Tomsik	TOM BK 2//3	Transformer	Thermal	Normal	Summer Peak
2024	SPPC	SPPC-NW	Incline	INC BK 1	Transformer	Reliability	Unplanned Contingency	Winter Peak

A	B	C	D	E	J	K	L	M	N	O	P
Year	Company	Region	Substation	Facility ID	NWA Energy Efficiency Capacity in 2029	NWA Demand Response Capacity in 2029	NWA Conservation Voltage Reduction Capacity in 2029	NWA Solar PV Capacity in 2029	NWA Battery Power Capacity in 2029	NWA Battery Energy Capacity in 2029	NWA Portfolio Estimated Cost for 2029
2024	NPC	NPC-NE	Gypsum	GYP BK 2	1,542 kW	0 kW	1,542 kW	0 kW	33,706 kW	71,944 kWh	$27,944,785
2024	SPPC	SPPC-TM	Northwest	NOW BK 2	951 kW	1,218 kW	0 kW	0 kW	3,851 kW	8,838 kWh	$4,369,907
2024	NPC	NPC-SE	Bicentennial	BCT BK 1//2	1,917 kW	1,907 kW	1,917 kW	0 kW	25,456 kW	137,301 kWh	$43,344,179
2024	NPC	NPC-SE	Keehn	KHN 1210	412 kW	1,107 kW	412 kW	4,238 kW	7,719 kW	58,010 kWh	$22,024,747
2024	SPPC	SPPC-NW	Buckeye	BUC 1276	250 kW	1,078 kW	250 kW	0 kW	658 kW	1,491 kWh	$1,303,844
2024	NPC	NPC-NE	Speedway	SPD BK 1//2	2,063 kW	1,000 kW	2,063 kW	5,000 kW	28,361 kW	348,108 kWh	$103,250,708
2024	NPC	NPC-SW	Tomsik	TOM BK 2//3	2,156 kW	3,840 kW	2,156 kW	5,000 kW	35,687 kW	229,155 kWh	$74,855,455
2024	SPPC	SPPC-NW	Incline	INC BK 1	686 kW	1,021 kW	686 kW	0 kW	7,716 kW	86,781 kWh	$25,026,096

A	B	C	D	E	Q	R	S
Year	Company	Region	Substation	Facility ID	T&D Infrastructure Upgrade Project Name	Estimated Cost	T&D Infrastructure Upgrade Reserve Margin in 2029
2024	NPC	NPC-NE	Gypsum	GYP BK 2	Gypsum 69/12 kV Bank 3 Addition [NE]	$1,720,533	0 kVA
2024	SPPC	SPPC-TM	Northwest	NOW BK 2	Northwest 120/25 kV Bank #2 Upgrade (Thermal N-0) [TM]	$4,968,664	12,437 kVA
2024	NPC	NPC-SE	Bicentennial	BCT BK 1//2	Bicentennial Bank 3	$2,232,599	4,180kVA
2024	NPC	NPC-SE	Keehn	KHN 1210	Larson 1201 Feeder [SE]	$4,527,706	2,712 kVA
2024	SPPC	SPPC-NW	Buckeye	BUC 1276	Pinenut 1252/1253 Tie (Thermal N-0) [CAR]	$404,733	0 kVA
2024	NPC	NPC-NE	Speedway	SPD BK 1//2	Speedway 138X69/12 KV Bank 3 [NE]	$3,257,277	0 kVA
2024	NPC	NPC-SW	Tomsik	TOM BK 2//3	Tomsik 138/12 kV Bank #1 [SW]	$2,488,322	0 kVA
2024	SPPC	SPPC-NW	Incline	INC BK 1	Incline #2 TFMR ADDN (Thermal N-0) [NTAH]	$13,178,782	18,912 kVA

The columns in DRP Update-Table 15 above that are not already explained as part of DRP Update-Table 5 are explained below:

- Column J: NWA Energy Efficiency Capacity in 2029 – A flexible input representing the amount of MW reduction from EE, either manually entered by the user or determined through use of the MS Excel Solver function, limited to a maximum of 2 percent[33] of the maximum MW loading on that selected day.

- Column K: NWA Demand Response Capacity in 2029 – A flexible input representing the total of: 1) an incremental amount of load reduction (27 percent of the total existing installed DR capacity connected to a distribution facility) achievable through a geo-targeted specially designed program for the existing DR assets rather than the "normal"

[33] This 2 percent assumption is greater than the annual energy savings targets of at least 1.1 percent statewide in response to legislation passed through Senate Bill 150 ("SB150") and Assembly Bill 223 ("AB223") by the 2017 Nevada Legislature, and assumes successful locationally targeted marketing yielding an increased local penetration of EE measures in the areas where demand reduction is needed to potentially defer a T&D wired solution.

operation of them in a manner designed to reduce overall system load, plus 2) a maximum of 1 MW of potential additional DR capacity that could be added to the distribution facility. The incremental amount of load reduction associated with the existing DR assets is manually entered by the user, while the potential additional amount of load reduction is either manually entered or determined through use of the MS Excel Solver function.

- Column L: NWA Conservation Voltage Reduction Capacity in 2029 – This is a flexible input representing the amount of MW reduction from installing Volt-VAR Optimization/Conservation Voltage Reduction, either manually entered by the user or determined through use of the MS Excel Solver function, limited to a maximum of 2 percent[34] of the maximum MW loading on that selected day.

- Column M: NWA Solar PV Capacity in 2029 – This is a flexible input representing the amount of MW reduction from installing in front of the meter utility-owned solar PV capacity, either manually entered by the user or determined through use of the MS Excel Solver function, limited to a maximum of 5 MW.

- Column N: NWA Battery Energy Storage System Power Capacity in 2029 – Already accounting for any MW reduction from EE, DR, CVR, and solar PV, this is the estimated MW power capacity of a in front of the meter utility-owned Battery Energy Storage System that would be required to address any remaining MW deficiency amount above the asset limit. The spreadsheet used this technology as a final step to address any remaining MW deficiency.

- Column O: NWA Battery Energy Storage System Energy Capacity in 2029 – Already accounting for any MWh reduction from EE, DR, CVR, and solar PV, this is the estimated MWh energy capacity of a in front of the meter utility-owned Battery Energy Storage System that would be required to address any remaining MWh deficiency amount above the asset limit. The spreadsheet used this technology as a final step to address any remaining MWh deficiency.

- Column P: NWA Portfolio Estimated Cost for 2029 – This is the total estimated cost for the NWA portfolio necessary to address the forecasted deficiency in 2029.

Importantly, NV Energy did not use the preliminary results of the NWA Screening Analysis Tool to definitively determine that a traditional wired solution should be chosen versus an NWA solution. Rather, it was used as a tool to support a decision to conclude the investigation of an NWA solution at that time (*i.e.*, if the PWRR of the estimated cost of the NWA solution was

[34] This 2 percent assumption is derived from the results of the Volt-VAR Optimization/Conservation Voltage Reduction Pilot Program conducted by NV Energy from March 2016 through April 2017 in conjunction with Docket No. 12-10013. The average energy savings from that pilot program for the summer months were approximately 2 percent.

notably greater than the PWRR of the savings that could be achieved by deferring or precluding the need for the traditional wired solution), or a decision to further consider an NWA solution (*i.e.*, if the PWRR of the estimated cost of the NWA solution was relatively close to or lower than the PWRR of the savings that could be achieved by deferring or precluding the need for the traditional wired solution). Notably, a decision to conclude the investigation of an NWA solution at that time based upon the preliminary result from the NWA Screening Analysis Tool does not mean that a particular constraint will not be examined for a potential NWA solution in the future. NV Energy examines distribution constraints and their traditional wired solutions whenever they pass the suitability/screening process and many constraints will be, and have been, re-examined annually for potentially cost-effective NWA solutions. Changeable conditions going forward (*e.g.*, load forecast and cost estimates) may or may not change the results of the NWA Screening Analysis Tool.

(4) NWA Analyses Further Consideration – 2023 Capital Plan

Discussed below is the one NWA analysis performed for the forecasted distribution constraints in 2024 that resulted in a preliminary minimally favorable financial result in the NWA Screening Analysis Tool for an NWA solution to defer the planned wired traditional capital upgrade project at most one year.

Northwest 120/25 kV Bank #2 Upgrade

The in-service date for this project has changed several times in the past two years. The Companies ran a sensitivity case with the NWA Screening Analysis Tool removing the benefits portion of the LNBA analysis. This case revealed a result highly favoring the wired traditional capital upgrade project in 2024 (an NWA PWRR of $1,067,928 versus a wired deferral savings of $637,924). This result in itself is not a definitive reason to eschew pursuit of a potential NWA portfolio solution, but because it means that the potential cost-effectiveness of the NWA portfolio solution is predicated off achieving the dollar value of the benefits as modeled (or achieving greater monetary benefit), something that has yet to be proven in practical application, there would be a notable risk at this point in time in actually achieving savings when implementing an NWA portfolio solution in this situation. Also, since the analysis revealed only an estimated $39,200 savings in implementing the NWA solution, a realistic minimal cost for interconnection and integration of a BESS, which is part of the NWA solution portfolio in 2024, would alter the results well in favor of the wired traditional capital upgrade solution. Finally, with the in-service date of the Northwest 120/25 kV Bank #2 Upgrade about a year away (from when the analysis was performed), it is unreasonable to expect that an NWA portfolio solution could be implemented in that timeframe.

Given the above, NV Energy deemed it prudent to continue implementing the Northwest 120/25 kV Bank #2 Upgrade project as planned in 2024.

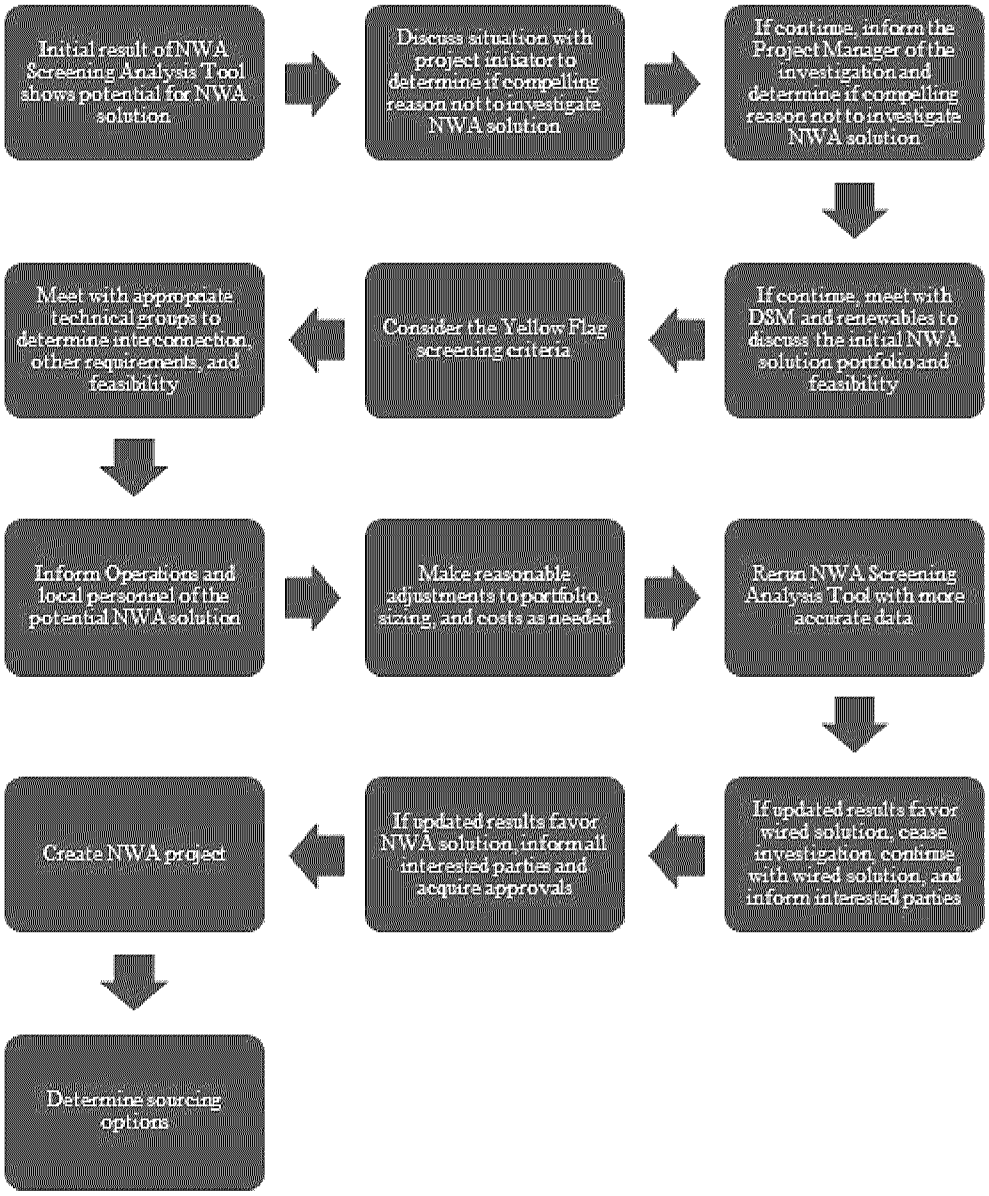
General Note

It is also important to note that, although an NWA analysis may have yielded a positive preliminary financial result from the NWA Screening Analysis Tool potentially favoring an NWA solution, this screening analysis does not yet include practical case-by-case considerations such as interconnection/integration costs, potential siting issues/costs, more accurate sizing and costs of the DER technologies in the NWA solution portfolio (*e.g.*, for the BESS component of the portfolio), and money that may have already been spent on the traditional wired solution to a constraint if the in-service date is a year away from the present or in that general timeframe. These considerations will generally tend to increase the actual cost of the NWA solutions from what was initially estimated in the NWA Screening Analysis Tool, tending to make them less cost-competitive against the traditional wired solutions.

(5) NWA Analyses Further Review Process

One of the aspects of its overall NWA process that NV Energy identified as requiring more clarity is the process following when the initial result of the NWA Screening Analysis Tool shows potential for a cost-effective NWA portfolio solution. To better outline this part of the process, the Companies have initially determined to follow the process outlined below in DRP Update-Figure 10.

DRP UPDATE-FIGURE 10:
NWA FURTHER REVIEW PROCESS



The above process attempts to account for the fact that the NWA Screening Analysis Tool may not be able to account for reasons why the project initiator, project manager, technical groups, or local NV Energy personnel would want the traditional wired capital project to proceed in a

particular instance, [35] the practical considerations in the Yellow Flag Screening Criteria, and the fact that better, more accurate costs are needed to more accurately determine if an NWA portfolio solution is truly more cost-effective. The process does not yet attempt to outline sourcing options as this aspect of the overall NWA process will be investigated in the coming years (as noted in Sections 8.C and 12).

The Companies are presently working through this process for a few forecasted constraints beyond 2024 and the results of those investigations will be reported in the 2024 DRP filing. Based upon its practical application in the coming months and potential feedback from stakeholders, the process may certainly be revised going forward.

c. Locational Net Benefits Analysis – 2023 Capital Plan

The deployment of DERs at different locations on the electric grid can result in potentially undesirable impacts in terms of thermal or voltage limitations on the distribution system, but also, potential benefits to NV Energy's electric system and customers. This locational value assessment, or LNBA, is essential for evaluating the economics of DERs deployed at different locations on the system and their potential to defer traditional wired capital upgrade solutions. Establishing the value of DERs can also support an understanding of the impact of DERs on long-term system needs related to load growth or reliability. Ultimately, when NWA solutions are deployed, this value can aid in informing the potential procurement process of such a solution, if needed.

Electric industry approaches for the economic valuation of DERs have evolved as new renewable generation deployments continue to increase. The process for determining the net value of DERs consists of identifying, describing, and valuing their quantitative and qualitative benefits and incremental costs. As discussed above in Section 3.A.1.c, NV Energy is in the process of working with consultants to determine what additional DER benefits may be appropriate to capture and quantify in its LNBA analysis and expects any changes in this respect to be reflected in the NWA analyses that the Companies will include as part of its 2024 DRP within its 2024 Joint IRP filing on or before June 1, 2024.

In 2015, the Commission identified eleven potential categories of benefits and costs associated with DG.[36] At that time, only five were considered known and measurable. The Commission has yet to revisit this list of potential benefits and costs for NWAs. Thus, for analysis purposes, the benefit and cost variables used by NV Energy are presently largely based upon the Commission's

[35] Such reasons could include that the capital project is: (1) one of several in a particular area that depend upon each other to achieve the goal of increasing electrical capacity or service reliability in an area to help foster increased growth, (2) presumed for planning purposes as a physical prerequisite for a second wired capital project that will connect to the electrical facilities constructed in the first wired capital project, or (3) part of an agreement with a developer or governmental agency in which construction of the capital project has been committed to occur.

[36] *See* Docket Nos. 15-07041 and 15-07042.

eleven variables. In performing the NWA analyses based upon NV Energy's 2023 Capital Plan, NV Energy applied techniques to quantify eight variables:

- Transmission Upgrade Deferral Cost – The value of the deferral of a transmission capital upgrade or asset replacement.
- Distribution Upgrade Deferral Cost – The value of the deferral of a distribution capital upgrade or asset replacement.
- Transmission Upgrade OMAG Cost – The value of the deferral of the incremental OMAG associated with a transmission capital upgrade or asset replacement.
- Distribution Upgrade OMAG Cost – The value of the deferral of the incremental OMAG associated with a distribution capital upgrade or asset replacement.
- Avoided Energy – The value of avoided energy based upon hourly energy prices as estimated by production cost simulation software ("PROMOD").
- Generation Capacity – The value of the avoided additional generation needed at peak demand as determined by optimal dispatch of resources.
- Energy Arbitrage – The value of charging a 25 MW four-hour battery during off-peak hours and discharging it during on-peak hours as estimated by PROMOD.
- Reduced Line Losses – The value of reduced transmission and distribution line losses as a result of load reduction or distributed generation.

NV Energy added an estimate of the benefit of reduced line losses to the LNBA calculation after the filing of its 2022 DRP Update, so this is new for this filing.

NV Energy performed the location-specific economic analysis of costs and benefits, the LNBA, using PWRR analysis that compared a traditional wired capital upgrade solution option deployed in the planned in-service year to an NWA plus deferred traditional wired capital upgrade solution option to meet the needs of the transmission and distribution systems. The LNBA itself is embedded into the comparative PWRR analyses in the NWA Screening Analysis Tool used to perform the Companies' NWA analyses, the results of which are shown above in the tables in Section 3.A.3.b.(3) and below in Section 3.B.3.b.(3).

The PWRR analysis in NV Energy's Screening Analysis Tool operates in the following manner for the NWA portfolio solution:

1. The total Capital Expenditure Recovery ("CER") is calculated on the basis of the gross capital cost of the NWA portfolio solution;

2. The total estimated benefits of the NWA portfolio solution are calculated;

3. The total estimated benefits are then subtracted from the CER to give the net revenue required;

4. The present value of the net revenue required is calculated; and

5. Those values are summed over the years of the analysis to give the cumulative present value of the net revenue requirement.

Based upon the above, the LNBA properly accounts for both the estimated costs and benefits of the DER technologies that may comprise an NWA portfolio solution.

While the LNBA is directed towards helping to guide where DERs can be most economically sited to defer investment in a T&D wired solution, it is important to understand that the LNBA is an embedded cost and benefit analysis. The LNBA conducted for integrated grid planning purposes does not quantify locational marginal costs or measure locational marginal pricing (as used in energy imbalance market pricing). In the DRP context, the LNBA provides a location-specific total cost and benefit valuation in the PWRR of the NWA solution, which is compared with the location-specific traditional wired capital upgrade solution to ensure the utility is developing a least-cost solution for its customers.

Stakeholder Process Related to the LNBA

Intervener testimony in the 2021 DRP filing in Docket No. 21-06001 suggested that additional DER benefit variables should be included in the LNBA. The Commission did not address this issue in its final order in that docket but did order NV Energy to convene a stakeholder process to consider and address the concerns raised in intervener testimony. The Companies convened this process in December 2022 and established a bi-monthly meeting schedule with interested stakeholders, holding meetings in March, April, June, and August of 2023 prior to this filing. This stakeholder process will continue as necessary to ensure the Companies' compliance with Directive 15 of the final order in that docket and the Companies will report on the results of that process in its 2024 DRP filing. Additionally, Section 8.D below discusses NV Energy's intention to review its LNBA for potential additional DER benefit variables.

D. Traditional Upgrade Projects and NWA Solutions Recommendations – 2023 Capital Plan

Based upon the constraints identified in the 2023 Capital Plan and the results of the NWA analyses discussed in Section 3.A.3.b.(3) for the year 2024, NV Energy recommends continuing to plan for the construction of the wired capital upgrade projects identified in that section, those being:

- Gypsum 69/12 kV Bank 3 Addition [NE];

- Northwest 120/25 kV #2 Upgrade (Thermal N-0) [TM];
- Bicentennial Bank 3;
- Larson 1201 Feeder [SE];
- Pinenut 1252/1253 Tie (Thermal N-0) [CAR];
- Speedway 138x69/12 kV Bank 3 [NE];
- Tomsik 138/12 kV Bank #1 [SW]; and
- Incline #2 TFMR ADDN (Thermal N-0) [NTAH].

B. Transmission Planning

NV Energy's Transmission System Planning Department ("Transmission Planning") is responsible for the reliability of the transmission grid consisting of voltages ranging from 55 kV to 500 kV. The criteria for transmission system reliability are based on applicable North American Electricity Reliability Corporation ("NERC") Compliance standards. More specifically, NERC Transmission Planning standard TPL-001-5 outlines transmission system performance requirements under several types of contingency conditions. For each type of contingency, certain performance is required. Where mitigation is required to meet performance criteria, Corrective Action Plans (*i.e.*, traditional utility solutions) are identified and implemented to address the reliability issue and bring performance within acceptable criteria. In addition to identifying existing reliability issues, Transmission Planning also specifies transmission system upgrades to accommodate both transmission and distribution system load growth. The requirements of these facilities are based on individual transmission interconnections and distribution load forecasting.

1. Load Forecasting

Transmission Planning uses the most recently approved extreme weather, or 1-in-10 year, IRP native load forecast and control area load forecast for planning purposes. When applicable, short-term distribution facility load forecasts from NV Energy's Distribution Planning department are used for studies on specific lines or substations.

The loading on networked transmission facilities is not directly related to the load forecast at a particular distribution transformer but is instead triggered by system flows. Thus, certain assumptions were made in these cases to simulate growing asset loading. These assumptions included using the average load growth rate in the immediate geographic area and using load or generation forecasts from projects driving these upgrades to simulate growing asset loading. Where possible, additional base cases were used to identify loading levels for various years. However, this methodology proved to be unreliable as different base cases included different

system-wide flows (inside and outside of NV Energy's area) that did not resemble a steady loading growth rate.

2. Technical Analysis Methodology

The NV Energy Capital Plan may require several different kinds of traditional wired transmission capital upgrade projects including breaker additions, new capacitor banks, new transmission lines, transmission line rebuilds and reconductors, transformer additions, and new substations. The types of constraints driving the need for the traditional wired transmission capital upgrade projects in the 2023 Capital Plan related to thermal overloads and reliability which are to go in service in 2024. The following sections describe the general methodologies used by NV Energy's Transmission Planning department when conducting NWA analyses to potentially mitigate these constraints.

A. NWA Analysis of Thermal Overloads

Thermal overloads describe scenarios where a transmission facility will exceed its MVA rating during normal operation or during contingency conditions. Increases in MW and MVAR flows can cause thermal overloads, but most often thermal overloads occur as the result of an increase in MW flows. This means that an NWA may be ideally suited for solving thermal overload issues as they can effectively reduce MW loading on transmission facilities through load shifting and load reduction to mitigate the overload. An NWA solution may also be effectively fine-tuned to mitigate a thermal overload by providing exactly the right amount of MW required to mitigate the overload, thus eliminating the infrastructure upgrade reserve margin generally seen with traditional wired capital upgrades.

Thermal overloads often occur only during peak summer loading conditions. This means that the thermal overload only occurs for a few months out of the year and only for a few hours each day during that season. An NWA solution can be sized to better fit the deficiency and only provide support when needed, whereas a traditional wired capital upgrade, notwithstanding the fact that it provides additional capacity to potentially accommodate abnormal system conditions throughout the year, permanently increases the capacity for a constraint that may only exist during certain periods.

b. NWA Analysis of Voltage Performance

Voltage performance describes scenarios where the voltage at a particular transmission bus is not maintained within standard limits during steady-state or contingency conditions. In the 2023 Capital Plan, problems with voltage performance are solved with the installation of capacitor banks to provide reactive support and increase the voltage. System voltage is often more sensitive to MVAR flows than it is to MW flows; thus, providing MVAR support with capacitor banks in these cases is the most cost-effective traditional method to solve poor voltage performance.

Due to the nature of the deficiency, some NWA solutions may not be as cost-effective in mitigating voltage concerns as they can be for thermal overloads. This is because capacitor additions result in a significant MVAR capacity addition with minimal land and equipment costs. For the analysis of NWA solutions to constraints where the traditional wired capital upgrade solutions are capacitor bank additions, the size of the proposed capacitor bank became the proxy for the size of the grid need. For an NWA to provide equivalent MVAR capability, a relatively large BESS or solar PV plus BESS installation would be required to provide the same benefit. Since the issue is not real power (MW) related, the potential NWAs are not able to leverage their main benefit (shifting/reducing MW load) to be more cost competitive. Like thermal overloads, voltage deviations are often the result of peak summer loading, sometimes combined with a contingency, and may only occur for a few months out of the year, and only then for a few hours on each of those days. A capacitor bank can be switched on and off to provide benefits when needed, similar to how an NWA solution can be implemented only during peak loading conditions to provide benefits when needed.

c. NWA Analysis of Reliability

A reliability constraint results when a contingency occurs resulting in a customer or transmission facility outage that could have been avoided had the transmission facilities had more sophisticated protection or sourcing. In the 2023 Capital Plan, there were transmission projects that required adding breakers for the purpose of improving reliability.

An NWA solution can provide the same benefits as a traditional wired capital reliability-based project by eliminating loss of load for certain contingencies, but with some limitations. The main limitation of using NWAs to defer or replace traditional wired capital reliability-based projects in the 2023 Capital Plan is that assumptions must be made regarding the duration that an NWA solution would need to be in service. Outage durations vary significantly depending on a large variety of factors, including the reason for the outage, weather, and safety. Outage history on a transmission facility can provide a helpful look at what some of the most common outage durations are for that facility, but they do not necessarily predict the frequency and duration of future outages. For the purposes of the NWA analyses, it was generally assumed that an NWA solution must be able to mitigate the reliability constraint for the same amount of time that installing a traditional wired capital solution would; at least one hour during peak loading conditions. Sometimes, the timeframe was increased beyond one hour based on historical outages for specific projects.

It is possible that an outage may last longer than an hour at any substation. In any situation that the outage lasts longer than one hour, or manual switching cannot be performed to bring customers back in service, there is the risk that the NWA solution may not have the capacity to provide service to customers. Traditional wired capital reliability-based projects, on the other hand, allow for loads to be served indefinitely. Attempting to size NWA solutions to serve load at these substations indefinitely results in extremely large NWA capacity solutions.

Another limitation is that outages can occur any hour of the day and any day of year. For this reason, solar PV is limited in its ability to act as an NWA solution on its own. Requirements for service overnight and other off-peak times may impose limitations on when BESS systems may be charged, as the system must be prepared to serve load at any time. Traditional wired capital reliability-based projects can effectively perform their function on-peak and off-peak, any day and time of the year.

(1) NWA Analysis of Reliability – Breaker Additions

In the 2023 Capital Plan, each breaker addition project was required to isolate a substation from faults on the lines serving that substation to eliminate loss of load. To effectively defer or replace a breaker addition, an NWA solution must be able to provide the same benefits as a breaker; eliminate loss of load for certain contingencies. To do this, the NWA solution must provide 100 percent of the MVA requirements at each substation impacted by the transmission outage for the entire duration of that outage.

(2) NWA Analysis of Reliability – Substation Additions

There are several ways in which a new substation may increase reliability for load and transmission facilities. In some situations, a new substation is constructed to replace a line tap used to serve load. Where a load is served by a tap of the transmission line, the load is subject to the reliability of the entire line. This means that any fault on the transmission line will result in an outage of the tapped substation. Constructing a new substation at the location of the line tap and folding in the transmission line will isolate the load from faults on the line, thus increasing reliability. An NWA solution may be able to effectively defer or replace the new substation by serving the tapped load for the duration of any outage the transmission source experiences.

Replacing an existing substation with a new substation is another way to improve reliability. There are some existing substations that suffer from poor reliability due to old/failing equipment and a legacy design. Depending on the extent of upgrades required to mitigate these reliability concerns, it may be more effective to build a new substation than upgrade the existing one. Replacing old equipment eliminates the cause of some outages and updating the legacy design of some substations can eliminate some contingencies that may have a significant impact on the surrounding transmission system. For example, replacing a legacy common bus-configured substation with a modern breaker-and-a-half configuration eliminates the possibility of a bus fault de-energizing large portions of, or in some cases all, the substation. In this situation, replacing the substation addition with an NWA solution may not be as feasible as it is with the tapped load case. An NWA solution would not be able to solve the problems caused by old equipment and would not be able to eliminate the critical contingencies seen in legacy design substations. It is possible that an NWA solution may be able to serve load lost during one of the critical contingencies at the existing legacy substation, but it would not be able to eliminate the widespread transmission line outages seen during that contingency.

(3) NWA Analysis of Reliability – Transmission Line Additions

There are many loads in the NV Energy service territory that are served by radial transmission lines, usually due to the rural nature of the loads. Any outage on these radial lines results in a loss of load with no way to restore service until the lines are placed back in-service. To improve reliability to these customers, a second transmission line may be constructed to add another source so that a loss of one line does not result in a loss of load. An NWA solution may be able to defer or replace the need for a second source by serving the loads on these radial transmission lines for the duration of the outage.

(4) NWA Analysis of Reliability – Transmission Line Rebuilds

As transmission lines age, they tend to experience more frequent outages due to the deteriorating condition of the lines. This can cause outages to the substations served directly by these lines as tapped substations and can interrupt networked transmission flows. An NWA solution could feasibly defer or replace transmission line rebuilds by serving 100 percent of the MVA requirements at each of the tapped substations for the duration of any outage impacting these lines but would not be able to mitigate the negative impacts of the loss of networked transmission flows.

Additionally, line rebuilds would accomplish other purposes that would not be accomplished with an NWA solution. A line rebuild would allow transmission lines to remain in service more often which would allow the system to take advantage of the networked transmission flows through these lines. Also, a line rebuild would solve any safety concerns with failing transmission structures and would significantly reduce the frequency that a line personnel would be dispatched to inspect the line and perform repairs whenever outages occur.

While an NWA solution could feasibly defer or replace line rebuild projects by serving the tapped substations during outages, it would not provide many of the benefits that are realized when the lines are rebuilt.

d. Impacts of a Networked Transmission System on an NWA Solution

Some of the benefits of using an NWA solution to defer or replace a traditional wired capital upgrade is that it can be finely tuned to minimize any infrastructure upgrade reserve margin and it can be strategically located to focus the benefits of the NWA solution on the impacted facility. This is true for systems that are radial (or open-looped) in nature, such as the distribution system, but this is not necessarily true for a networked system like the transmission system. In a system that has a radial configuration, the flows on the system are directly proportional to the amount of load being served by that system. For example, the flows on a distribution transformer or radial transmission line are equal to the amount of load being served by that transformer or line. In a radial system, the flow is always in the same direction from the source to the load.

This is not the case for a networked transmission grid. In the transmission system, the magnitude and direction of flows through networked lines are impacted by many different factors including load, generation dispatch, interchange, outages on other lines, and phase shifters. This makes it much more difficult to predict what future flows will be on these transmission facilities. Additionally, changes in load will not have a proportional impact on the networked facilities serving the load as they do in radial facilities, especially if there are several transmission sources serving the bus that the distribution substation transformer is connected to. The impacts on each transmission source will change depending on overall conditions throughout the entire system.

This is where implementing an NWA solution in a networked transmission system becomes challenging. If a load increase causes an overload of a distribution substation transformer, then an NWA solution sized close to the amount of the overload can be strategically placed on the distribution system to mitigate the overload. If that load increase caused an overload of one of the transmission sources to the substation, then placing an NWA solution sized close to the amount of the overload on the transmission bus may not mitigate the overload. This is because, in the networked transmission system, the implementation of the NWA solution will impact each transmission source differently, akin to how the load addition itself impacted each transmission source differently. The more sources connected to the same substation, the more difficult it becomes to focus the benefits of the NWA solution on any one element. When the benefits of the NWA solution are shared among several elements, the size of the solution may need to be increased well beyond the size of the overload. This eliminates one of the advantages of using an NWA solution to replace a traditional wired capital solution – minimizing infrastructure upgrade reserve margin. When this advantage of the NWA solution cannot be utilized, its cost-effectiveness decreases. The current NWA Screening Analysis Tool used for NWA analysis does not consider how networked a system facility is and, thus, cannot directly calculate the necessary NWA solution capacity on a networked system. Consequently, power flow analysis is performed to accurately determine this, with this result then being entered into the NWA Screening Analysis Tool for comparison to the traditional wired capital solution.

3. Grid Needs Assessment – 2023 Capital Plan

a. Transmission Constraints and Projects Identification – 2023 Capital Plan

In the normal course of business, Transmission Planning identifies traditional wired capital upgrades through several continuous and cooperative processes. The primary source for capital upgrade recommendations is the Corrective Action Plan documents identified in the Companies' NERC reliability standard compliance analysis effort. This analysis is performed by modeling various transmission grid scenarios representing specific network assumptions (*e.g.*, season, time of day, neighboring utility operations) and simulating NERC-defined contingencies while observing system performance. These scenarios are developed to represent stressed conditions on the present system and forecasted system topologies out to 10 years. If the system fails to perform

within the NERC (or, by extension, the Western Electric Coordinating Council ("WECC")) defined performance criteria, a Corrective Action Plan to mitigate the issue is prepared.

Secondarily, risks to public safety and reliability on transmission assets that are not captured by the NERC analysis are identified by operational teams and communicated to Transmission Planning. Transmission Planning evaluates these risks and recommends solutions in collaboration with NV Energy's functional engineering groups. An example of a reliability risk that would not be captured by NERC analysis would be a load served on a radial transmission line. Under NERC standards, if a disturbance on the line triggers protective relaying and opens the line, the load can be disconnected as a "consequential load loss." While allowable under NERC standards, this result would be analyzed by operational teams and likely forwarded to Transmission Planning. Another example of a reliability risk that would be identified by operational teams would include equipment deterioration that does not yet violate a specific standard. Though these issues do not directly violate reliability standards, they are reviewed nevertheless, and projects are initiated to minimize risk to safety and increase system reliability. Finally, some transmission capital upgrades are driven by generator interconnections and growth due to major load additions.

To complete the GNA, Transmission Planning followed a similar methodology as that used by NV Energy's Integrated Grid Planning department. All traditional transmission wired capital upgrade projects in NV Energy's 2023 Capital Plan were reviewed and filtered through the NWA Suitability/Screening Criteria described above in Section 3.A.3.b.(1).

The 2023 Capital Plan contained 92 transmission projects, 55 of which met critical suitability Criterion A (constraint anticipated to occur between January 1, 2024, and December 31, 2029). Of those meeting Criterion A, five projects also met the critical suitability Criterion B (constraint based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading, energy consumption, or load shifting would eliminate or defer the constraint). Two projects met both Criteria A and B and were in the 2024 timeframe covered by this 2023 DRP Update. As a result, two traditional transmission wired capital upgrade projects were evaluated through the NWA Screening Analysis Tool process (one in the Nevada Power territory and one in the Sierra territory).

The identification of transmission grid needs varies from the distribution process in two important ways:

- Current, widely-used transmission planning software does not have the ability to perform time-series ("temporal") analysis over a 24-hour or annual period. The software is only capable of simulating steady-state "snapshots" of specific system conditions. Grid needs are identified from a series of modeled snapshots ("base cases") that are tuned to determine "worst-case" conditions. These models only identify the size of the overload for that specific condition and do not provide insight into the length of the condition or annual frequency of the condition. As a result, additional assumptions must be made to determine

the duration of a grid need and expected frequency (*e.g.*, the expected time to restore a line that has suffered an outage, the likelihood of an outage, and the typical duration of peak loading conditions).

- Transmission Planning models must integrate additional data points that have significant impact on the sizing and timing of grid needs. Unlike the distribution system, the transmission system performance is impacted by system-wide conditions including generation dispatch, phase-shifter operation, western interconnection-wide flow patterns outside of NV Energy's balancing area, major generation additions, major load additions, major topology upgrades and other dynamic variables. As these variables change, the power flow driving the capital upgrade can change significantly.

These two factors underscore the fact that there is significantly more uncertainty in the size, length, and required in-service date of a transmission capital upgrade when compared to a distribution capital upgrade. Historically, this limitation in transmission grid need sizing accuracy has not been an issue because the incremental sizing of a traditional wired capital capacity upgrade is frequently much larger than that of a custom NWA solution. Also, a wired-solution asset lifetime (typically 55 – 70 years) is long enough to ensure that the asset will provide its intended benefit even if the driving variable (such as a 1-in-10-year summer heat wave) does not occur in the year the project goes into service.

In addition, assumptions about the frequency of outages and of future generation had to be made to approximate the grid need to a much tighter accuracy than is typically required for transmission level analysis. When applicable, the assumptions were noted in the NWA Screening Analysis Tool for each project. Once the grid need was determined, an NWA portfolio solution was developed to mitigate the grid need using the same methodology described in the distribution GNA. Despite these differences, the transmission GNA was able to describe the grid needs in a similar way to the distribution GNA.

Since this 2023 DRP Update is applicable only to the year 2024, brief descriptions of the two constraint situations in that year (one in the Nevada Power territory and one in the Sierra territory) are provided below.

2024

Two constraints on the Companies' transmission system were identified which are planned to be mitigated through a traditional capital upgrade project in 2024:

Sahara 69 kV PCB Additions

Improve reliability for customers served out of the Sahara 69 kV Substation with the addition of two 69 kV power circuit breakers. Sahara Substation has a coincidental summer peak load of

approximately 65.3 MVA. A disturbance on the Sahara-San Francisco 69 kV line (2.5 miles long) and/or the Sahara-Winterwood 69 kV line (2.1 miles long) causes a loss of all load at the Sahara Substation. Historically, the entire load served from Sahara Substation experiences approximately 2-3 outages per year due to 69 kV line problems. Most of these outages are due to line lightning disturbances.

Bordertown-California 120 kV Line

The Bordertown 345/120 kV transformer addition and the Bordertown to California 120 kV line addition are required to relieve line overloads that transfer the 345 kV system to the 120 kV system that serve the Reno load. The California to Bordertown 120 kV line is required to provide an additional line for power to flow to the load. The project is required to mitigate these potential NERC TPL-001-5 violations, improve operation of the bulk electric system in northwest Reno, and to serve balancing area load through the California phase shifter.

DRP Update-Table 16 below summarizes the pertinent information for each constraint. The data shown is for the year 2029 as this is the ending year of the analysis period. The table is broken into several graphics for ease of viewing, with Columns A through E repeated for identification purposes. The first graphic shows the identifying information, the second shows the deficiency information, and the third shows the traditional capital upgrade project information for each situation.

DRP UPDATE-TABLE 16:
2023 CAPITAL PLAN GNA
SUMMARY FORECASTED TRANSMISSION CONSTRAINT AND TRADITIONAL CAPITAL UPGRADE SOLUTIONS TABLE

A	B	C	D	E	F	G	H	I
Year	Company	Region	Substation	Facility ID	Facility Type	Constraint Type	Operational Condition	Seasonal Identification (Peak, Off-Peak, All)
2024	NPC	NPC-NE	Sahara	SA 6902L/6903L	Breaker	Reliability	Unplanned Contingency	All
2024	SPPC	SPPC-TM	Bordertown	BTN/CAL Substations	Line	Thermal	Unplanned Contingency	Peak

A	B	C	D	E	J	K	L	M	N	O
Year	Company	Region	Substation	Facility ID	Total Estimated Duration of Deficiency in 2029	Total Estimated Days of Deficiency in 2029	Estimated Duration of Deficiency on Peak Day in 2029	Criteria (Ratings)	Initial Deficiency	Estimated Maximum Deficiency in 2029
2024	NPC	NPC-NE	Sahara	SA 6902L/6903L	8,760.0 hours	365 days	24.0 hours	N/A	62 MVA	69.5 MVA
2024	SPPC	SPPC-TM	Bordertown	BTN/CAL Substations	720 hours	90 days	8.0 hours	161 MVA	40 MVA	67 MVA

A	B	C	D	E	P	Q	R
Year	Company	Region	Substation	Facility ID	T&D Infrastructure Upgrade Project Name	Estimated Cost	T&D Infrastructure Upgrade Reserve Margin in 2029
2024	NPC	NPC-NE	Sahara	SA 6902L/6903L	SAHARA 69KV PCB ADDITIONS	$7,227,932	N/A
2024	SPPC	SPPC-TM	Bordertown	BTN/CAL Substations	BORDERTOWN TO CAL SUB 120KV LINE	$48,926,133	N/A

Each of the columns followed the same format as described in the distribution GNA with two exceptions. The duration of deficiency was estimated by using 24-hour duration when the driving variable could not be determined or when the driving variable was considered reliability. Reliability required a 24-hour duration because an outage could occur at any time and for any length of time with no way to predict ahead of time. A system peak-related deficiency used a four-hour duration, or a duration based off historical and anticipated loading.

Many of the projects have an undefined T&D Infrastructure Upgrade Reserve Margin "N/A." For most of these projects this is because the upgrades are required for reliability purposes rather than thermal or voltage deviations. When an upgrade is required for a reliability reason, such as a breaker addition, the Upgrade Reserve Margin concept does not apply.

Although the 2021 DRP was filed about two years ago, there were some notable changes in the in-service dates of the transmission traditional capital upgrade projects and in the projects themselves in the 2024 timeframe between the filing of the 2021 DRP and this 2023 DRP Update. DRP Update-Table 17 below summarizes these changes and illustrates the volatility of the transmission capital plan, even in the short-term.

DRP UPDATE-TABLE 17:
2023-2024 TRANSMISSION TRADITIONAL CAPITAL UPGRADE SOLUTIONS COMPARISON TABLE

Transmission Constraint/NWA	Current In-Service Year	June 2021 Filing	September 2022 Filing	September 2023 Filing	Comment
Westside Substation 230 kV Switch Replacement	4/1/2022	✓			In service 12/15/2021
Emerson 120 kV Breaker Addition	4/30/2022	✓			In service December, 2022
Burnham - Ford 138kV Fold into Pebble	5/1/2022	✓			In service 3/14/2022
PECOS 230/138KV BANK #5	6/24/2022	✓			In service 6/24/2022
Round Mountain 2307 Line Tap	12/31/2022	✓			Change in scope-NWA Not applicable
Chukar Capacitor Bank	4/1/2023	✓			Cost of NWA cannot compete with a capacitor bank for supplying VARs. Capacitor bank is best investment for ratepayers. In service May, 2023
Clark - Concourse 138KV Re-Conductor	12/31/2023	✓			Upgrade is required for interconnection studies, cannot be deferred or replaced with NWA
Tam 69 kV PCB Addition and Remote End Work at Highland and Decatur	4/30/2023	✓	✓		In service May, 2023
LVC - Highland 138kV fold into Miller - Chuckwalla Solar DNR	6/1/2023	✓			Upgrade is required for interconnection studies, cannot be deferred or replaced with NWA
CABANA 138 KV PCB	6/1/2023	✓	✓		In service May, 2023
ELC - NW 138 kV Reconductor - Chuckwalla Solar DNR	9/1/2023	✓			Upgrade is required for interconnection studies, cannot be deferred or replaced with NWA
SAHARA 69KV PCB ADDITIONS	6/1/2024	✓	✓	✓	
Steamboat 120 kV Breaker Additions	5/28/2025	✓			ISD outside DRP Update range
LAHONTAN-LOVELOCK 617 LINE REBUILD	10/24/2025	✓	✓		ISD outside DRP Update range
BORDERTOWN TO CAL SUB 120KV LINE	11/26/2024	✓	✓	✓	
Charleston Substation [NW]	5/30/2025		✓		ISD outside DRP Update range
Winston 138kV Switchyard	5/30/2025	✓	✓		ISD outside DRP Update range
Stockyard 120/63 kV Substation (Buckeye Replace)	2/17/2026	✓	✓		ISD outside DRP Update range

Transmission Constraint/NWA	Current In-Service Year	June 2021 Filing	September 2022 Filing	September 2023 Filing	Comment
ROSANNA 69KV PCB ADDITIONS	6/1/2025	✓	✓		ISD outside DRP Update range
GREEN VALLEY 138 KV PCB	6/1/2025	✓	✓		ISD outside DRP Update range
OREANA-LOVELOCK (652) REBUILD	8/1/2028		✓		ISD outside DRP Update range
CRAIG 138KV PCB ADDITION	6/1/2026	✓	✓		ISD outside DRP Update range
BALBOA 69KV PCB ADDITIONS [SE]	6/1/2026	✓	✓		ISD outside DRP Update range
#626 Antelope - Battle Mountain 60kV Pole Replacements	12/31/2026		✓		ISD outside DRP Update range
WASHINGTON 69KV PCB ADDITIONS	6/1/2027	✓	✓		ISD outside DRP Update range
RUSSELL 138KV PCB ADDITION	6/1/2027	✓	✓		ISD outside DRP Update range
Rainbow 69kV PCB Additions	6/1/2028		✓		ISD outside DRP Update range
Bighorn - Oasis 69KV Transmission Line	6/29/2028	✓			Removed from 10 year plan
Bordertown 120/25 kV Transformer Addition (OAP)	6/30/2028	✓	✓		ISD outside DRP Update range
BRUNSWICK-BUCKEYE 635 LINE REBUILD	12/31/2028	✓	✓		ISD outside DRP Update range
Bannock 120kV Capacitor Bank	In Service	✓			In service November 2021
Carlin Trend Reactive Support - Bell Creek Capacitor	In Service	✓			In Service May 2022
North Valmy 345/125 kV Transformer 3 Uprate	In Service	✓			In Service
Machacek Sub 230kV MO Switch Upgrades	N/A	✓			Cancelled

b. Non-Wires Alternative Analysis – 2023 Capital Plan

As described in the distribution context above, an NWA is a solution to an identified constraint(s) on the Companies' electric transmission or distribution systems that may include the deployment of one or more DERs in lieu of a traditional wired solution.

(1) NWA Suitability/Screening Criteria – 2023 Capital Plan

The transmission grid needs were subjected to the same NWA Suitability/Screening Criteria described above. No transmission projects were eliminated for Yellow Flag issues.

(2) NWA Analysis Methods – 2023 Capital Plan

The two projects that met both critical suitability Criteria A and B in 2024 were examined using the same NWA Screening Analysis Tool used for distribution to determine the feasibility of an NWA to cost-effectively defer or replace the proposed wired solution. When projects were found to feasibly defer or replace the traditional wired alternative based upon an estimated PWRR analysis, these projects were recommended for further analysis to validate the results and

ultimately decide whether to pursue an NWA solution or continue to pursue the planned wired solution.

(3) NWA Analyses Discussion and Results – 2023 Capital Plan

2024 – Sahara

DRP Update-Table 18 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wired solution deferral savings.

DRP UPDATE-TABLE 18:
SAHARA 69 kV PCB ADDITIONS
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	0.00	0.21	1.00	3:15:00 PM	1.30	0.88	62.58	61.75	$ 28,489,654	$ 1,050,448	($27,439,206)
2025	0.00	0.21	1.00	3:15:00 PM	1.32	0.88	63.26	62.42	$ 28,792,310	$ 1,468,299	($27,324,011)
2026	0.00	0.21	1.00	3:15:00 PM	1.33	0.88	64.16	63.30	$ 29,195,853	$ 1,863,119	($27,332,733)
2027	0.00	0.21	1.00	3:15:00 PM	1.35	0.88	65.07	64.20	$ 29,603,781	$ 2,236,177	($27,367,603)
2028	0.00	0.21	1.00	3:15:00 PM	1.37	0.88	65.99	65.09	$ 30,011,709	$ 2,588,673	($27,423,036)
2029	0.00	0.21	1.00	3:15:00 PM	1.39	0.88	66.89	65.98	$ 30,415,251	$ 2,921,741	($27,493,511)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

2024 – Bordertown – California Sub 120 kV line

DRP Update-Table 19 below shows the portfolio of NWA DER technologies and sizes that addressed the forecasted overloads in the years 2024 through 2029 resulting in a minimized NWA PWRR for each year, and the comparison of the NWA PWRR versus the wired solution deferral savings.

DRP UPDATE-TABLE 19:
BORDERTOWN-CALIFORNIA SUBSATION 120 KV LINE
NWA PORTFOLIO AND COMPARATIVE PWRR

ISD	EE (MW)	Ex. DR (MW)	Add. DR (MW)	DR Start	CVR (MW)	Solar (MW)	Battery (MW)	Battery (MWh)	NWA PWRR	Wired Deferral Savings	Net (Wired-NWA) + = savings
2024	4.25	0.21	1.00	5:15:00 PM	4.25	4.04	41.55	93.04	$ 27,742,286	$ 6,308,646	($21,433,640)
2025	4.31	0.21	1.00	5:15:00 PM	4.31	4.41	44.62	106.51	$ 30,743,724	$ 8,592,497	($22,151,226)
2026	4.36	0.21	1.00	5:15:00 PM	4.36	4.41	47.11	117.99	$ 33,264,442	$ 10,776,771	($22,487,671)
2027	4.43	0.21	1.00	5:15:00 PM	4.43	4.41	50.38	133.67	$ 36,665,148	$ 12,865,810	($23,799,338)
2028	4.50	0.21	1.00	5:15:00 PM	4.50	4.41	53.64	149.35	$ 40,065,853	$ 14,863,765	($25,202,088)
2029	4.57	0.21	1.00	5:15:00 PM	4.57	4.41	56.91	165.42	$ 43,527,289	$ 16,774,608	($26,752,681)

As reflected in the table, the NWA PWRR exceeded the PWRR of savings of deferring the wired capital upgrade project for all the analysis years. Therefore, the results of the NWA screening analysis did not support further consideration of NWA portfolio solutions to address the constraint in lieu of the wired capital upgrade project.

DRP Update-Table 20 below summarizes the identifying information, NWA portfolio parameters, and traditional capital upgrade project information for each of the above constraints. The data shown is for the year 2029, as this is the ending year of the analysis period. The table is broken into several graphics for ease of viewing, with Columns A through E repeated for identification purposes.

DRP UPDATE-TABLE 20:
2023 CAPITAL PLAN
SUMMARY FORECASTED TRANSMISSION CONSTRAINT AND NWA SOLUTIONS TABLE

A	B	C	D	E	F	G	H	I
Year	Company	Region	Substation	Facility ID	Facility Type	Constraint Type	Operational Condition	Seasonal Identification (Peak, Off-Peak, All)
2024	NPC	NPC-NE	Sahara	SA 6902L/6903L	Breaker	Reliability	Unplanned Contingency	All
2024	SPPC	SPPC-TM	Bordertown	BTN/CAL Substations	Line	Thermal	Unplanned Contingency	All

A	B	C	D	E	K		L	M	N	O
Year	Company	Region	Substation	Facility ID	NWA Demand Response Capacity in 2029 (MW)	NWA CVR Capacity in 2029 (MW)	NWA Solar PV Capacity in 2029 (MW)	NWA Battery Power Capacity in 2029 (MW)	NWA Battery Energy Capacity in 2029 (MWh)	NWA Portfolio Estimated Cost for 2029
2024	NPC	NPC-NE	Sahara	SA 6902L/6903L	1.21	1.37	0.88	66.89	65.98	$30,415,251
2024	SPPC	SPPC-TM	Bordertown	BTN/CAL Substations	1.21	4.57	4.41	56.91	165.42	$26,752,681

Importantly, NV Energy did not use the preliminary results of the NWA Screening Analysis Tool to definitively determine that a traditional wired solution should be chosen versus an NWA solution. Rather, it was used as a tool to support a decision to conclude the investigation of an

NWA solution at that time (*i.e.*, if the PWRR of the estimated cost of the NWA solution was notably greater than the PWRR of the savings that could be achieved by deferring or precluding the need for the traditional wired solution), or a decision to further consider an NWA solution (*i.e.*, if the PWRR of the estimated cost of the NWA solution was relatively close to or lower than the PWRR of the savings that could be achieved by deferring or precluding the need for the traditional wired solution). Notably, a decision to conclude the investigation of an NWA solution at that time based upon the preliminary result from the NWA Screening Analysis Tool does not mean that a particular constraint will not be examined for a potential NWA solution in the future. NV Energy examines transmission constraints and their traditional wired solutions whenever they pass the suitability/screening process and many constraints will be, and have been, re-examined annually for potentially cost-effective NWA solutions. Changeable conditions going forward (*e.g.*, load forecast and cost estimates) may or may not change the results of the NWA Screening Analysis Tool.

(4) NWA Analyses Further Consideration – 2023 Capital Plan

Based upon the above results for the NWA analyses performed for transmission constraints in 2024, none of the projects in that timeframe are being considered further for a potential NWA solution.

c. Locational Net Benefits Analysis – 2023 Capital Plan

Refer to Section 3.A.3.c above for a discussion of the Companies' LNBA. The distribution and transmission analyses in this regard were performed similarly.

d. Traditional Upgrade Projects and NWA Solutions Recommendations – 2023 Capital Plan

Based upon the constraints identified in the 2023 Capital Plan and the results of the NWA analyses discussed in Section 3.B.3.b.(3) for 2024, NV Energy recommends continuing to plan for the construction of the Sahara 69 kV PCB Addition and the Bordertown – California Substation 120 kV line projects in 2024.

As of the date of this filing, NV Energy is not planning to defer or replace any traditional transmission wired capital projects with an NWA solution in the 2024 timeframe.

Section 4. Transportation Electrification Plan Update

In 2021, SB448 established requirements for a Transportation Electrification Plan ("TEP") as an additional requirement within the DRP. The provisions of SB448 were subsequently codified in NRS 704.741(4)(f), which requires that the DRP must include a TEP, and NRS 704.7867, which contains the requirements of the TEP itself. NV Energy submitted its first TEP on September 1, 2022, in Docket No. 22-09006 as part of the third amendment to its 2021 Joint IRP. Moving forward, the TEP will be submitted with the DRP when it is filed as a part of NV Energy's triennial IRP filing or as a part of future DRP update filings.

Upon receiving the final order in Docket No. 22-09006 on May 17, 2023, NV Energy has put forth best efforts to progress forward on the TEP and its programs. As approved, the TEP is largely an expansion of NV Energy's ERTEP programs which were already underway. Specific TEP developments have focused solely on program management for TEP implementation and execution. This TEP update will provide a general description of the programs as well as NV Energy's update for the 2024 program year, and financial data from the inception of the programs to June 30, 2023, which is provided below in DRP Update-Table 21.

DRP UPDATE-TABLE 21:
TEP BUDGETS AND EXPENDITURES

Program/Administration	Authorized Budget ($)	Actual Expenditures ($)[1]
Interstate Corridor Charging Depot	15,329,000	-
Electric School Bus Vehicle-to-Grid Trial	28,253,000	-
Inflation Reduction Act Innovation Demonstration	1,000,000	-
Program Management	4,751,000	2,254,926
Contingency	7,178,000	-
Total	**56,511,000**	**2,254,926**

[1] Actual expenditures as of June 30, 2023.

Due to the continuous efforts to stand up the programs, the actual expenditures thus far have been to support plan development, utility administration, and program management. The breakdown of the actual expenditures is as follows:

- 92 percent attributed to outside services employed that supported plan development and program management.
- 8 percent attributed to utility administration that supported team and program development.

Section 10.3 of the TEP that was filed as a part of Docket No. 22-09006 outlined that NV Energy would provide program level data that includes: program participation, charging network performance, percentage of spend benefiting underserved communities, customer outreach, and education. The TEP programs are still under development and are not ready for open enrollment.

This data will become available once enrollment begins and charging stations are installed and operating. NV Energy will report this data in future TEP filings and DRP updates.

The first TEP stakeholder engagement meeting occurred on August 25, 2023. The meeting topics were selected to solicit each stakeholders' priorities, their best lessons learned, and knowledge of other successful transportation electrification programs in other states.

A. Plan Programs Overview and Update

1. Interstate Corridor Charging Depot Program

NV Energy started building out an interstate charging network with the Nevada Governor's Office of Energy ("GOE"), the Nevada Department of Transportation ("NDOT"), and the Nevada Division of Environmental Protection ("NDEP") through the Nevada Electric Highway program that began in 2015. NV Energy's ERTEP Interstate Corridor Charging Depot Program was developed to facilitate the deployment of more charging infrastructure and associated electrical equipment for EV charging along major interstates and highways in Nevada. The TEP's Interstate Corridor Charging Depot Program furthers these efforts.

NV Energy continues to work with NDOT to advance plans for additional National Electric Vehicle Infrastructure ("NEVI") compliant stations along the Alternative Fuels Corridor that align with the ERTEP and TEP Interstate Corridor Charging Depot Program.

a. Program Details

The site profiles for the Interstate Corridor Charging Depot Program consist of 2 single-port 19.2 kW level 2 chargers and 6 direct-current ("DC") fast charging ports made up of 4 single-port 150 kW chargers and 2 single-port 350 kW chargers. The sites also include shade canopies for protection against the weather. Site hosts can request a reduction of the number of chargers within the standard site profile with collaboration with NV Energy.

Site hosts can choose a turnkey solution from NV Energy or assume responsibility for charger installation and maintenance themselves. The program is designed to reduce the cost to site hosts choosing to offer public charging to tourists, travelers, and local EV drivers.

b. 2024 Program Year Update

NV Energy will continue to work with the NDOT to identify gaps in EV charging availability along priority interstates and highways, with consideration for planned development. NV Energy will continue to engage with potential sites for participation on US 95, US 50, and Interstate 80, within NV Energy's service territory, that the NDOT has identified as a challenge for Alternative Fuel Corridor Status based upon NEVI guidelines. No changes to the program are proposed.

2. Electric School Bus Vehicle-to-Grid ("V2G") Trial

The Electric School Bus V2G Trial was developed and approved to provide additional funding to enable more school districts to participate in electrifying their fleet. The primary objectives of this trial are to facilitate the deployment of charging infrastructure and associated electrical equipment to school bus electrification and to demonstrate V2G capabilities for optimal grid integration. The chargers deployed through this trial serve school districts working to decarbonize their school bus fleets and for the chargers to provide valuable grid integration capability through the V2G capable charges. This trial will assess the ability of the school bus fleet batteries to provide grid services, inform the process and technical needs for integration at scale, and provide electricity back to the grid as well as moderate charging to help with grid reliability. NV Energy will work with the school districts to develop V2G trials that maximize benefit to historically underserved communities by prioritizing electrifying routes that serve those communities first, where feasible.

A. Program Details

The program provides two different site profiles to support small and large school district needs consisting of 10 or 20 single-port, V2G 60 kW DC fast chargers. School districts can request a reduction of the number of chargers within the standard site profile. NV Energy will work with the school districts to understand the basis for the modification request.

To be eligible, the school district is required to apply for program funding. Priority is given to rural public-school districts. If priority school districts pass on funding, participation will be allowed for Clark County School District and Washoe County School District at a separate fleet yard than the ERTEP School Bus V2G Trial.

NV Energy will build, own, and operate the charging infrastructure installed as part of the Electric School Bus V2G Trial. There is an option to transfer ownership of customer-side infrastructure and responsibility for the operations and maintenance to the school districts, if requested.

b. 2024 Program Year Update

NV Energy will continue to prioritize rural public-school districts, which are: Douglas, Elko, Esmeralda, Eureka, Humboldt, Lander, Lyon, Mineral, Nye (excluding the City of Pahrump), Pershing, and Storey.

To obtain the needed supplemental funding required for participation in the program, NV Energy, in collaboration with Nevada Clean Energy Fund, submitted a statewide application for the Environmental Protection Agency ("EPA") Clean School Bus Grant on August 22, 2023.

3. Inflation Reduction Act Innovation Demonstration Program

The Inflation Reduction Act ("IRA") provides funding to support deployment of additional infrastructure to promote renewable integration in eligible communities. To take advantage of the federal funding opportunity, this program allocates funding to support the deployment of NV Energy-owned solar generation and battery energy storage at sites that include shade canopies as part of the site profile for the Interstate Corridor Charging Depot Program and Urban Charging Depots.

A. Program Details

The inclusion of solar and battery storage to a transportation electrification site provides the opportunity for NV Energy to study electric vehicle infrastructure, battery storage and on-site renewable generation on utility owned infrastructure that should support additional flexibility to help increase grid utilization and provide a flexible resource for optimal grid integration.

b. 2024 Program Year Update

NV Energy is evaluating different federal funding matching opportunities to pair with the IRA Innovation Demonstration Program, to deploy distributed energy resources within electric vehicle infrastructure.

Section 5. Barriers to Deployment of DER

As set forth in NAC 704.9237(2)(e) and NRS 704.741(4)(e), one of the required elements of a DRP is a discussion of potential barriers to the deployment of DERs. NV Energy initially identified several potential barriers to the deployment of DERs during the development of its 2019 DRP filing and identified them again in its 2021 DRP filing. They are reiterated below, grouped into three categories:

- **Integration/Interconnection of DERs with the distribution grid:**
  - If the number of requests to interconnect DERs increases, additional resources and modification of the interconnection process may become necessary.
  - As the types of DERs technologies increase, interconnection tariffs may need to be updated.
  - Where an individual DER fails to deliver its anticipated benefits at the anticipated costs, the entire portfolio of DERs may be impacted.
- **Market limitations on the ability of DERs to deliver promised benefits:**
  - Notwithstanding Federal Energy Regulatory Commission ("FERC") Order 2222, DER participation in the wholesale energy marketplace is still in its infancy.
  - Resource performance and intermittency are issues that may have to be addressed contractually.
  - Competing needs will affect the ability of DERs to provide market services while at the same time addressing local system needs and providing customer benefits.
  - Although decreasing in general, the potential cost of DERs technologies, including integration costs, may still present a higher cost as compared to traditional solutions.
- **Distribution system operational and infrastructure capability to handle DER value:**
  - High penetrations of DERs can present challenges on the distribution grid in terms of voltage regulation, utility equipment overloads and reliability concerns.
  - Limited visibility of DER locations, knowledge of real-time operation, and lack of control can present challenges to system operators.
  - Limited ability to granularly forecast DERs locally can inhibit proper planning and impact system conditions.
  - Operational constraints should be monitored, communicated, and enforced to meet local system needs.

The Companies developed some potential solutions that could address these barriers and are investigating others. DRP Update-Table 22 below captures these efforts.

DRP UPDATE-TABLE 22:
POTENTIAL BARRIERS TO DER DEPLOYMENT AND SOLUTIONS

Barriers to Deployment	How the DRP can help to address…	Status
Integration/Interconnection of DERs with the distribution grid	Review and modify (if necessary) interconnection process to handle growing number of DER requests.	Gathering data from other states. Anticipate full Rule 15 update in 2024.
	Review and modify (if necessary) interconnection rules/tariffs to accommodate growing number of emerging DER technologies.	Gathering data from other states. Anticipate full Rule 15 update in 2024.
	Provide additional useful information to developers so they can customize and target successful solutions.	Publicly-accessible DRP Web Portal provides HCA, GNA, and load profile information.
Market limitations on the ability of DERs to deliver promised benefits	Ensure that the DRP responds to maturation of the market.	To be determined; anticipate investigating in 2024-2025.
	Develop contracts to mitigate DER performance and reliability issues.	To be determined; anticipate investigating in 2024-2025.
	Provide value stack from DER through LNBA, which includes both system and locational benefits. Develop priority of services to ensure proper system and customer benefit.	LNBA performed within the NWA analysis process. Additional potential benefits are being investigated with consultant support. Priority of services to be determined.
	Evaluate costs of DER portfolios versus traditional solutions, including interconnection and integration costs.	NWA/LNBA performed with ability to add interconnection and integration costs.
Distribution system operational and infrastructure capability to handle DER value	Identify the necessary investments in operational tools, devices and systems to address potential technical challenges posed by increased DER penetration.	DERMS approved in 2021 DRP filing. First phase released in May 2023, with subsequent phases through 2026.
	If appropriate, provide support for DERMS-type solution acquisition.	Approved in 2021 DRP filing. Project in process.
	Support development of DER forecasting methodologies for planning purposes and DERMS-type solutions for operational benefits.	DERMS approved in 2021 DRP filing. Project in process. DER Forecasting and Valuation tool being developed in 2023 to support 2024 filing.

Section 6. DRP Coordination with Other Components of the IRP and Commission-Approved Programs

A. Coordination with Other Components of the IRP

The integrated resource planning process continues to evolve as technologies and public policies emerge. In 2017, the passing of SB146 required the Companies to file a DRP and incorporate DER planning into the IRP planning process. NV Energy filed its first DRP as an amendment to the 2018 IRP. The Companies' 2021 IRP filing marked the first time the DRP was incorporated into a full IRP filing. The IRP presents the joint system-level loads and resources needed to meet native load customer requirements over the long-term. The DRP addresses distribution-level resources and sets forth the plans and strategies to meet near-term locational system and customer needs. Integrating DERs will impact the need for the Companies to build new capital wired distribution upgrades, will impact the net loading on specific feeders within the system, and can delay the need for such distribution facilities.

While NAC 704.9225 requires that the Companies present a 20-year load forecast for long-term integrated planning, the DRP requires a shorter timeframe for forecasting, with a minimum of six years beginning with the year after the DRP is filed. As described in the load forecast section of the Third Amendment to the 2021 IRP ("Amendment"), NV Energy adjusted the system-level load forecast for the penetration of privately-owned generation, energy storage and EV capacity, and incorporated the latest information available to forecast the adoption rates and energy use and savings characteristics of all DERs.

Due to a combination of more programs offered by the Companies and Nevada state policy goals encouraging EV use, the Amendment load forecast assumes that electric plug-in vehicles, as a percentage of new vehicles sold in Nevada, will increase to 51.2 percent by 2030 and increase at 0.1 percent per year thereafter. This compares to the projection in the 2021 IRP that sales of such vehicles would constitute 11.2 percent of all new vehicle sales by 2030 and increase by 0.1 percent thereafter. This resulted in an updated statewide incremental EV energy sales forecast of approximately 191 GWh annually by 2030 (combined for both Companies).

As the amount of privately-owned generation and energy storage technologies continues to increase on the Companies' electric system, it will increasingly impact system-level load forecasts and supply-side options. Notwithstanding this, the evaluation of DER technologies as alternatives to investment by the utility in traditional wired solutions to identified constraints on the T&D system (*i.e.,* the NWA process) has not yet impacted the need for supply-side and transmission assets in the integrated resource planning process.

NV Energy will continue to monitor the deployment of DERs through both existing Commission-approved programs and the DRP process and will assess the impact of these resources in future

IRPs. As DERs continue to expand on the NV Energy system, a stronger relationship between the DRP and other components of the IRP is expected to develop.

B. Coordination with Existing Commission-Approved DER Programs

1. Existing Commission-Approved Programs, Tariffs, and Incentives Addressing the Deployment of DERs

a. Demand Side Management Programs

A key component of the IRP is the utility's cost-effective portfolio of programs for reducing customers' demand on the electrical grid pursuant to NRS 704.741. The Commission reviews NV Energy's existing and proposed demand-side portfolio every year either in a triennial IRP or in an annual update filing. In this 2023 DRP Update, the programs are termed EE and DR and are included in the definition of distributed resources in NRS 704.741(7)(b).

In addition to offering cost-effective alternatives to supply-side resources, the programs have contributed to achieving Nevada's Renewable Portfolio Standards ("RPS") policy goals. NV Energy's DSM portfolio of programs is cost-effective at the plan level and results in annual energy savings of at least 1.1 percent of the weather-normalized retail sales forecast in each of Nevada Power's and Sierra's territories. For 2022, the DSM portfolio of programs achieved a benefits-to-cost ratio using the Non-Energy Benefit Total Resource Cost ("NTRC") test of 2.45.

(1) EE Programs

NV Energy maintains a robust portfolio of Commission-approved EE programs focused on delivering energy savings measured in kWh. The portfolio is bundled into education services, residential services, and non-residential services categories to provide energy conservation measures for residential, commercial, and industrial customers. These Commission-approved programs include:

- The Energy Education program, which delivers energy use education via presentations, media outreach, community events, professional trainings, and live educational performances at schools. This program is used as a gateway for customer awareness that leads to customer participation in DSM programs or undertaking EE measures independent of the available DSM programs;
- The Home Energy Reports program, which delivers reports to residential customers to inform and motivate them to change or modify their behavior in context with similar households. The program encourages customers to actively save energy by providing personalized information, energy-saving products and services, and practical ways to save energy and money, which drive participation in other DSM programs;

- The Online Energy Assessments program, which provides an online energy assessment enabling customers to save energy and reduce their energy bills;
- The In-Home Energy Assessments program, which provides a customized energy analysis conducted by a PowerShift Energy Advisor for customers to gain greater insight into how their household uses energy, how their home performs, and what they can change to make their home more efficient;
- The Direct Install and Home Improvement program, which provides residential customers with direct installation of low-cost energy efficient measures in their home by a trained energy advisor. The value proposition will be further enhanced when implemented in combination with in-home energy assessments and DR offerings;
- Program Development, which explores DSM strategies by conducting small-scale tests of emerging products or services that may enhance NV Energy's current portfolio of programs or identify a new cost-effective DSM program;
- The standalone Low-Income program, which provides energy efficient appliances and products to low-income customers who experience high energy bills due to the costs of operating inefficient appliances;
- The Residential Equipment and Plug Loads program, which provides both incentives and rebates to customers in the form of reductions to out-of-pocket costs for purchasing more efficient appliances and other electric products. The program is marketed to customers as the Home Energy Saver program that includes discounted retail appliance, product or equipment measures; pool pump measures; and residential air conditioning measures;
- The Energy Smart Schools program, which is designed to facilitate EE and peak demand reduction in public schools and higher education facilities by offering rebates for EE projects and technical assistance to facility managers;
- The Business Energy Services program, which is designed to generate long-term energy savings and peak demand reduction by providing rebates and technical services to facilitate the implementation of energy efficient measures in existing and new commercial and industrial facilities. This program also offers grants to non-profit facilities to help them implement EE measures and reduce their operating costs; and
- The Residential Codes and New Construction program, which provides support to the residential new construction market to increase the energy efficiency of Nevada homes. The program engages with residential homebuilders by providing early information about upcoming changes in codes and their associated changes to energy efficiency baselines.

Several of these programs can help reduce or defer local grid constraints, particularly those driven by distribution facility loading. The NWA analyses in this 2023 DRP Update reflect a maximum

two percent potential incremental reduction in demand (and a consequential reduction in energy usage) via EE programs.

NV Energy provided an update on its DSM programs in its 2023 DSM Annual Update in Docket No. 23-06044.[37]

(2) DR Programs

NV Energy's DR programs are key components to the DSM portfolio because they actively manage and shape loads and assist in placing aggregated demand-side energy resources on par with traditional supply-side resources. The DR programs offer tools for NV Energy and its customers to reduce energy consumption, change usage patterns, and gain a greater understanding of how energy is used. Additionally, these programs provide economic value in managing energy markets' high peak energy prices, while increasing the value for both NV Energy and its customers. NV Energy primarily engages customers in DR to provide them with technologies, such as smart thermostats, and services that create tangible operational and EE benefits. The DR programs can provide dispatched load control for either reliability (*i.e.*, grid emergency) or economic reasons and can be used for peak shaving, peak shaping, and operating reserves.

When customers participate in NV Energy's residential and commercial DR programs, NV Energy installs devices that temporarily interact with those customers' end-use loads during pre-scheduled DR events that help reduce peak demand. NV Energy sends signals to these devices during DR events to alter the operation of customers' end-use loads in a way that reduces energy consumption and shifts a significant amount of energy consumption outside of peak demand hours. Additionally, during emergency events, NV Energy can lower agricultural load in the Sierra territory through a manual notification and customer self-curtailment process to preserve the integrity of the grid.

NV Energy is recruiting customers with qualifying Energy Storage System ("ESS") technologies identified from the list of customers known to have previously installed BESS, including customers that received Clean Energy program energy storage incentives. The target enrollment for 2023 is 73 premises. Communication between NV Energy and the customer's BESS is necessary for DR dispatch signals and energy monitoring. DR dispatch signals provide the battery control system with a start time, duration, and control commands with payload for discharge. NV Energy anticipates that each battery will provide an average demand reduction of 3.15 kW during events.

A detailed assessment of the current residential and commercial DR programs can be found in the DSM Annual Update narrative in Docket No. 23-06044.

[37]Docket No. 23-06044, Joint Application for approval of NV Energy's 2023 Combined Annual Electric Demand Side Management Update Report, Narrative Section 3.

In aggregate, if all NV Energy's DR resources were dispatched at the same time on a hot summer day for an hour, these resources would provide approximately 265 MW/MWh of grid-wide system-level emergency load relief. Typically, the system is dispatched for economic reasons. In this operational mode, the dispatch of DR resources is spread across peak hours, flattening out the grid-wide system peak and reducing reliance on peak-priced purchased energy and fuel. When not scheduled for economic reasons, a portion of the DR resource system can be queued as an operating reserve resource. Operating reserve resources must meet the requirements for ten-minute non-spinning reserves. Below are some key summary statistics of NV Energy's existing DR resources:

- Emergency DR Capacity: 265 MW;
- Ten-minute Non-spinning Reserve DR: 210-220 MW;
- Typical Peak Offset for Economic/Peak Shaping DR: 130-150 MW;
- Total Customers Enrolled: 97,387; and
- Total Devices/End-use Loads Under Control: 148,331.

NV Energy recognizes the need to diversify customer assets (*e.g.*, lighting controls, grid interactive water heaters, pool pumps, energy storage, EV charging stations) participating in DR programs to provide higher and more flexible levels of DR capacity and capability outside of the summer months. In 2021, Pool Pump DR and Grid Interactive Water Heater DR were field trials under Program Development. For 2022 and 2023, all Pool Pump DR and Grid Interactive Water Heater DR participants have been participating in DR events and are currently being scheduled on the same days as smart thermostats. As more renewable resource capacity comes online, DR assets are expected to be used to help manage the variability of renewable resources and be used to absorb excess solar generation by control of storage devices. As DR technologies continue to improve, they will support greater control of loads and the integration of other DERs onto the electric grid in the future.

NV Energy's current DR portfolio emphasizes direct load-control techniques to primarily affect load control within the timeframe of one-day-ahead to ten-minutes-ahead. As more asset types capable of operating in the ten-minutes-ahead to four-seconds-ahead timeframe increase, NV Energy will need to supplement or build out additional DR infrastructure to successfully integrate the larger number of assets. Such infrastructure is discussed below in Section 9.

b. Clean Energy Programs

Pursuant to NRS 701B.190, NV Energy was responsible for delivering clean energy ("CE") programs aimed to support the Nevada's goal of expanding and accelerating the development of emerging technologies in the renewable and DER space. The CE portfolio of programs aimed to

promote renewable energy technologies and installation of energy storage market development technologies. The current CE portfolio of programs included:

- Solar Energy Systems Incentive Program;[38]
- Lower Income Solar Energy Program ("LISEP");
- Electric Vehicle Infrastructure Demonstration ("EVID") Program; and
- Energy Storage Program.

The above programs ended due to their statutorily determined expiration dates or program expenditure funding limits.

In 2022, portfolio energy credits from the Companies' combined CE programs contributed to 8.8 percent of NV Energy's current year RPS credit total. These programs have helped NV Energy exceed the RPS requirement that mandated not less than 29 percent of the utility's energy supply to come from renewable sources in 2022.[39] The key goals of the CE programs were to offer customer support for new technologies, ensure that the implementation of the CE programs were conducted in a prudent and effective manner, and provide technical advice on DER interconnections via the Rule 15 tariff. The CE programs stopped accepting new applications effective July 1, 2023. The programs are now winding down as pending CE projects are completed and the final incentive payments are processed.

(1) EVID Program

NV Energy is committed to supporting the acceleration of EV deployment and the expansion of EV charging infrastructure statewide. Pursuant to NRS 701B.670, NV Energy launched several programs under the EVID umbrella,[40] which include the:

- Non-Residential, Residential, and Multi-Family Charging Program (previously known as the EV Charging Stations Incentive Program);
- Electric School Bus Incentives Program;
- EV Custom Grant Program[41]; and
- Nevada Electric Highway Program.[42]

[38] The Solar Energy Systems Incentive Program was fully subscribed as of June 5, 2019. Current activities are to close out active incentive reservation applications.
[39] NRS 704.7821.
[40] For more information on the EVID programs, refer to Docket No. 22-02002, NV Energy's 2022 Annual Clean Energy Plan, Section E.
[41] No longer accepting new applications.
[42] All Nevada Electric Highway program projects have been completed.

This portfolio of programs was strategically designed to expand the EV charging infrastructure by providing incentives to offset the cost of engineering, procurement, and installation of EV charging stations. As the number of charging stations increases, so will their demand for electricity from the electric grid. Demand Response will play an instrumental role in the electric grid's ability to accommodate this DER technology.

(2) Energy Storage Program

Pursuant to NRS 701B.223, NV Energy implemented an Energy Storage Program[43] to promote and advance the market adoption of emerging energy storage technologies. As directed by NRS 701B.226, NV Energy divided the program into two subcategories based on the customer type and nameplate size in kW of energy storage devices: a Small Energy Storage Program ("SESP") and a Large Energy Storage Program ("LESP"). The Small Energy Storage Program incentivized residential and non-residential customers pursuing energy storage systems with a nameplate capacity less than 100 kW. Customers eligible for the program received a larger incentive by electing to enroll in a Time-of-Use ("TOU") rate. The LESP incentivized non-residential customers pursuing energy storage systems with a nameplate capacity of at least 100 kW but not greater than 1,000 kW. This program was intended to prioritize installations that served critical infrastructure facilities such as hospitals and airports.

Innovative use cases of energy storage included reducing peak demand for electricity, avoiding or deferring investment on the utility's electric grid infrastructure, and improving the electric grid's reliability and operation. The Energy Storage Program was available to NV Energy's residential and commercial customers who have previously installed a renewable energy system or were currently installing one alongside their energy storage system. Commercial customers also had the option to install a standalone energy storage system through the program.

The Energy Storage Program officially ended after June 30, 2023, following the Commission's order in Docket No. 23-02001. The decision to close the program was made after it was reported that minimal funding remained.

c. Economic Recovery Transportation Electrification Plan

Prior to creating the TEP, SB448 directed NV Energy to create a plan to accelerate transportation electrification in this State for the period beginning January 1, 2022, and ending on December 31, 2024, and to provide economic recovery benefits and opportunities for the creation of new jobs in Nevada. The Economic Recovery Transportation Electrification Plan ("ERTEP") was approved

[43] For more information on NV Energy's enhancements to its Energy Storage Program, refer to Docket No. 21-02004, NV Energy's 2021 Annual Clean Energy Plan, Section D.

on January 12, 2022, and has the following five statutorily-required electric vehicle infrastructure programs focused on developing public infrastructure:[44]

1. Interstate Corridor Charging Depot Program;
2. Urban Charging Depot Program;
3. Public Agency Electric Vehicle Charging Program (focused on community centers, colleges and universities, ad capitol complexes);
4. Transit, School Bus and Transportation Electrification Custom Program:
    a. Transit Custom Grant;
    b. Electric School Bus V2G Trial;
    c. Transportation Electrification Custom Grant; and
5. Outdoor Recreation & Tourism Program.

All infrastructure in the ERTEP has standardized technical requirements for electric vehicle charging equipment to ensure safety, reliability, customer experience and optimized grid integration. All EV charging stations installed through ERTEP must meet minimum standardized requirements pursuant to the Commission's order.[45]

Some ERTEP programs evolved from the earlier EVID Programs due to advances in technology and standards. The Companies will bring forth learnings and recommendations from the ERTEP programs in future filings.

d. Expanded Solar Access Program

The Expanded Solar Access Program ("ESAP") was created as a result of Assembly Bill 465 in 2019. The bill requires an electric utility to offer an expanded solar access program to residential customers who consume less than 10,000 kWh of electricity per month. Among the requirements for the ESAP is the program broaden access to solar energy in an equitable manner and that the program provide participating low-income residential customers with a lower rate. This bill requires an electric utility, in implementing the expanded solar access program, to make use of at least a certain number of community-based solar resources ("CBSR") and utility-scale solar resources.[46] These resources are owned and operated by NV Energy. One such resource generates at approximately 350 kW and is in southern Nevada. The resource was installed at Mojave High School and was operational starting in December 2021. NV Energy continues to monitor the

[44] Docket No. 21-09004, January 12, 2022, Modified Final Order at 10.
[45] *Id.* at 138-40.
[46] NRS 704.7865.

generation from this solar asset and relevant data and information was included in Docket No. 23-03001.

Two additional CBSRs, which were selected by NV Energy residential customers, were made public on November 15, 2021, and the Companies shortly thereafter commenced discussions with the local municipalities. The Companies worked with the City of Las Vegas and City of Reno to finalize the respective leases and right of entry for the Freedom Park CBSR (Nevada Power) and the Moana CBSR (Sierra), respectively. Both these CBSRs are in construction at this time with a targeted commercial operation date of December 31, 2023.

e. Other Related Tariffs and Rules

NV Energy offers several tariffs and tariff riders that support DER deployment. These include price-responsive and NEM tariffs that customers can further enroll in to help their rate of return on their DER investments. The electric grid also benefits from customer participation in the form of peak load reduction. A high-level summary of each tariff or tariff rider is provided below:

Rule 9 EV Allowance Adder – While not a tariff, the Rule 9 EV Allowance Adder, approved by the Commission in the Companies' TEP, supports investments in EV charging infrastructure. The EV Allowance Adder increases the total Rule 9 allowance available for applicable residential projects and will support the additional installation requirements necessary to prepare for increasing EV infrastructure development.

- **TOU Tariffs** - The TOU tariffs provide customers with a choice. Customers who are willing to use less electricity during periods when the total demand of energy is highest (peak hours) will save money by shifting their energy usage to times with lower rates. These rates are higher during daytime and early evening hours (peak usage and demand hours) and lower during nighttime hours (off-peak hours). Nevada Power is proposing a new TOU rate period in its ongoing General Rate Case filed in Docket No. 23-06007. As proposed, the TOU rate would change the summer on peak period to 3:01 p.m. to 9:00 p.m, eliminate the summer mid peak period for large commercial customers, add weekend days to the summer on peak period for residential and small commercial customers, and propose non holiday weekend days be added to the critical peak pricing event days for residential customers.

  In the modified final order of Docket No. 22-06014, the Commission approved Sierra's proposed timeframe change to all tiers in the TOU rate tariffs that shifts the summer on-peak period from 1:01 p.m. to 6:00 p.m. to 3:01 p.m. to 9:00 p.m. The Commission also approved Sierra's request to expand the Summer months from July through September to June through September, eliminate the Summer Mid-Peak period for Sierra's large customers, eliminate the Winter On-Peak and Winter Mid-Peak TOU periods (which creates a single Winter TOU for residential and commercial customers), and add weekends

to the Summer On-Peak period (which creates a daily Summer On-Peak TOU period for residential and commercial customers).[47] To help customers who are uncertain about the best rate for their lifestyle, a comparison is made between the TOU rate and the regular flat rate for the first 12-month period. If the TOU rate was more costly, NV Energy will credit the difference back to the customer and give the customer the option to move back to the flat rate.

NV Energy supports various TOU rate variants, such as:

- Critical Peak Pricing ("CPP") – This is a rate variant of the base TOU rate in which a higher-priced time period, or critical peak period, can be dispatched to customers via various customer communication channels on a day-ahead basis. Critical peak periods are not known in advance but are dispatched during times of high wholesale power prices. NV Energy's current version of CPP has a fixed start time and fixed duration.
- Daily Demand Pricing ("DDP") – This rate variant offers a lower monthly basic service charge and fixed energy rate throughout the day. However, the rate includes Demand and Facility charges based on times when a customer's energy usage peaks. This rate is best suited for customers who have many electrical appliances and equipment.

- **Electric Vehicle TOU Tariffs -** The below rates are for customers who own an electric vehicle and wish to enroll into a Time of Use rate.
  - Electric Vehicle Recharge Rider ("EVRR") – This rate rider incentivizes customers to charge their EV during off-peak hours when loading on the electric grid is low. It allows a customer to pay a discounted rate if they charge their EV during the utility's off-peak hours. This discounted rate applies to all energy used at a residence during that time, not just electricity used to charge an EV.
  - Electric Vehicle Commercial Charging Rider ("EVCCR") – This rate rider is offered to bundled large service commercial customers who install separately metered direct current Fast-Charging ("DCFC") EV charging stations. This rider is applicable only to those services used for the primary function of charging electric vehicles. The off-peak period was recently updated to 12 a.m. to 12 p.m. to better encourage EV charging when solar production is plentiful and before the system load peaks for the day.
  - NV Energy Electric Vehicle Charging Network ("NVEVCN") – This rate rider describes the rates for using an electric vehicle charger owned by NV Energy. Time of use rates are incorporated into the NVEVCN tariff to encourage EV charging when solar production is plentiful and before the system load peaks for the day.
- **Electric School Bus V2G Trial ("ESB-V2G")** – This new tariff facilitates the Electric School Bus V2G Trial within ERTEP and the TEP. The objective of this trial is to

[47] Docket No. 22-06014, February 16, 2023, Modified Final Order at 290-291, para. 870.

demonstrate V2G integration with electric school buses to mitigate charging impact on system peaks and to understand the co-benefits for the participating public school districts and NV Energy. This rider is limited to participants in the trial, or school districts that previously received a utility incentive towards the cost of electric school bus in EVID utilizing V2G technology and is intended to assist in determining the feasibility of using the stored energy of an electric vehicle as a DER asset for grid services. The credit for discharged energy will be calculated for each hour as the lesser of:

- the hourly system incremental generation cost; or
- the NV Energy average hourly Load Aggregation Point ("ELAP") price. The ELAP can be found on NV Energy's FERC Open Access Same-time Information System ("OASIS") site.

- **Expanded Solar Energy Rate -** Eligible NV Energy residential and business customers can derive their electricity from a mix of utility-scale and community-based solar resources through ESAP. Customers selected to participate in the program pay a special rate, which replaces the Base Tariff Energy Rate ("BTER") and Deferred Energy Accounting Adjustment ("DEAA").
- **The NEM Tariff** - This tariff applies to the deployment of renewable DERs. Under this tariff, the customer receives bill compensation for excess energy that is exported to the grid. Net metering allows customers to use the energy generated by their renewable energy system to offset their monthly power bill. Customers may participate in net metering even if they choose not to participate in the CE incentive programs.
- **NV GreenEnergy Rider ("NGR")** - Customers can choose to "go green" by participating in the NGR. The NGR offers Sierra and Nevada Power customers the option of taking 100 percent or 50 percent of their energy from renewable resources by electing to pay an additional amount on their monthly bill based on usage. The NGR requires a minimum commitment of 12 months or until service on a customer account is discontinued. Customers will receive a renewal notice for additional 12-month periods. The amount will be listed on monthly bills as the NGR charge. Sierra and Nevada Power's commercial customers may also participate through negotiated terms, which are subject to Commission approval.
- **Optional Load Management – Automation Services Rate Rider ("OLM-AS")** - This tariff rider supports residential and small commercial customers who participate in the DR load control. It specifies monthly load control bill credits by device type and performance-based credits for load control event participation as measured by NV Energy's smart meters. The tariff rider also specifies the conditions and characteristics of billing credit transactions and load management periods related to the air conditioning load control program.

- **Interruptible Irrigation ("IS-2") Tariff** - This tariff is available to eligible Sierra agricultural customers who agree to interrupt irrigation pump service during system emergencies. This service is applicable to electricity used solely to pump water to irrigate land for agricultural purposes. Customers participating on this tariff must be capable of responding to utility load control notification within 30 minutes to curtail water pumping under electricity grid emergency conditions.

2. Cost-Effective Coordination Between the DRP and Existing Commission-Approved DER Programs

NV Energy recognizes the need to strategically coordinate the joint implementation of multiple DER technologies that:

- are required by statutes and regulations;
- are approved in separate Commission filings;
- have different cost recovery mechanisms; and
- may be pursued by different departments within NV Energy to achieve different benefits.

Functionally, NV Energy merged the DSM and CE departments to better strategize in areas that could greatly benefit from leveraging resources and improving collaboration and program coordination. NV Energy has a great deal of knowledge from various DR field demonstrations that provide lessons learned and best practices for future projects. NV Energy will be evaluating a variety of activities and/or tools for efficient utility operations and coordinated program efforts.

a. EE Support of Locational Benefits

Energy efficiency is a readily deployable, clean energy resource that supports long-term planning objectives and delivers lasting demand and energy reduction. These programs do not fundamentally provide operational flexibility to the electric grid or locational dispatch capability in the way that DR programs can, but they are still capable of providing locational benefits. NV Energy acknowledges the viability of deploying geo-targeted EE to lower the overall demand loading of specific electric facilities at specific locations, making EE an important NWA resource. Specific locations may include underserved communities and resource or capacity constrained areas.

Energy conservation measures exhibit characteristic energy savings profiles, or energy savings curves, that are considered when using EE to mitigate constraints on the grid. Energy efficiency measures have varying capabilities to offset energy use at times of peak demand. Peak demand at the system level does not always coincide with the peak demands on a particular substation transformer, distribution feeder, or transmission line, which vary depending on the customer and

load types on the facility. Energy efficiency resources create lasting reductions in customer demand that allow for the quantification of capacity cost savings. The cost-effectiveness models used by NV Energy determine an EE measure's avoided capacity benefits at the system level not at the feeder level. Currently, a generalized cost estimate for avoided T&D capacity is used in DSM planning. The adopted process values this lasting effect of EE measures by identifying the savings resulting from deferring T&D capital investments over the useful life of the investments.

b. DR Support of Locational Benefits

NV Energy's DR information technology and communications systems support the locational, geo-targeted dispatch of DR resources. NV Energy has already begun to include some initial methodologies to estimate the impact of DR on certain distribution facilities already identified as requiring additional traditional wired capital infrastructure to reliably meet customer load.

Four geo-targeted DR program demonstrations have already been completed at Village Substation in 2019, Northwest Substation (in the Nevada Power territory) in 2020, Leavitt Substation in 2021, and Bicentennial Substation in 2022. In each, premises actively enrolled in current DR programs were used with all device technologies available in the DR portfolio. The Village Substation demonstration resulted in a total DR capacity of 1,440 kW with 39 DR events dispatched. The Northwest Substation demonstration resulted in a total DR capacity of 3,284 kW with 48 DR events dispatched. The Leavitt Substation demonstration resulted in a total DR capacity of 1,775 kW with 39 DR events dispatched. The Bicentennial Substation demonstration resulted in a total targeted DR capacity of 2,520 kW with 12 events dispatched to devices technologically capable of targeted DR. Load reduction achieved by DR events at the substation level varied across events with maximum hourly kW reduction between 501 kW and 1,148 kW for Village Substation, between 1,434 kW and 2,686 kW for Northwest Substation, between 289 kW and 1,191 kW for Leavitt Substation, and between 526 kW and 1,997 kW for Bicentennial Substation.

In 2023, the estimated total capacity of the available DR assets connected to Bicentennial Substation is approximately 2.6 MW, which represents the maximum load shed capability using system average load impact factors.

For each demonstration, NV Energy targeted an optimized dispatch of DR resources installed at premises on the substation's distribution feeders. This required re-programming the DRMS to include a larger number of discrete resources at the feeder level for a more targeted event dispatch. The DSM technical team developed a strategy designed to shape the peak load on the distribution feeders.

As proven by the DR program demonstrations at four of its distribution substations, NV Energy is able to successfully utilize geo-targeted efforts when needed by distribution and system-level operations and has shown that this method can be relied upon to support meeting customer load in high peak events.

NV Energy continues to explore utilizing DR assets within an NWA solution portfolio to recruit additional customers around substations who would have the most impact on reducing the peak loading of constrained distribution assets. The higher impact programs would include those that address the loads driving peak, such as residential air conditioning measures, commercial air conditioning measures, and DR.

NV Energy utilizes its DRMS, which allows the grouping of load control devices into discrete resource groups, to accommodate locational dispatch by geographic zones, or by substation, transformer, or feeder. However, due to the old architecture of the DRMS, the locational dispatch cannot be done in real-time and requires a few-hour notice to reconfigure the system. There is a role type in DRMS that allows distribution operators to log into the system to see how much load curtailment is available and to dispatch an event. The DRMS was originally setup to accommodate larger geographic zones, meaning that, if an event is needed to be launched on a specific feeder, time is required to reconfigure the system. For older device technologies, when the DR assets on a specific feeder are dispatched, all the devices on that feeder will be dispatched, and also the other devices in that particular zone.[48]

In 2018, locational dispatch testing was performed to verify expected operating characteristics and in preparation for new IT systems integrations among the DRMS, the Advanced Distribution Management System ("ADMS"), and the GIS. The DSM technical services team continually researches methods of optimizing resource groupings in DRMS from larger geographic zones to a more granular set of resources to enable a more accurately targeted dispatch at the feeder level. The distribution system network topology within the DRMS is updated daily, as opposed to the historical practice of once a year before the start of the load control season.

Despite these improvements and due to its age and original specifications, the DRMS does not fully support DR that uses load management for ancillary services down to the four-second timeframe. The database also does not support retrieval and storage of device state information for devices such as smart inverters for DG systems or energy storage devices, along with more modern command sets related to voltage support or frequency regulation. However, by using external systems, DRMS supports the Open ADR 2.0 standard allowing dispatch of peak shaving and peak shaping load control events to storage devices. Additional systems and software are required for a more optimal dispatch of DG systems for fast DR support of distribution system operations and renewable energy variability management.

NV Energy's current DR operational capability for locational load management exceeds its DER valuation and cost-effectiveness modeling capability in that current cost-effectiveness models use

[48] The load management system supervising NV Energy's fleet of two-way paging programmable communicating thermostats—the Carrier Comfort Choice ("CCM") system—is limited to a maximum of 14 operational groups. Hence, the CCM groups are mapped according to larger zones. Devices on a particular feeder can still be dispatched, but the other CCM devices in the zone would also be dispatched. NV Energy's other load management systems were similarly mapped, however, they can be remapped and regrouped on a more granular basis.

a system-level generalized avoided cost of T&D rather than locational values. Calculation of more granular locational benefits and marginal cost of distribution capacity value could be used to better target DR deployment and dispatch DR assets. Similar to EE programs, DR programs' avoided energy, avoided capacity and system average T&D costs are included in the cost-effectiveness modeling for DSM programs.

Demand response programs provide more flexible grid operational benefits than EE and are an important component of potential NWA solutions. Thus, NV Energy's DSM portfolio is a balance of both EE and DR programs. The NWA analyses in this 2023 DRP Update reflect utilization of geo-targeted programs designed to maximize the load reducing capability of existing installed DR assets on the constrained grid facilities identified in those analyses, like the demonstrations at Village, Northwest, Leavitt and Bicentennial Substations. Additionally, the NWA analyses allow for an additional amount of DR capacity up to one MW to be modeled and compete or combine with other DER technologies to reduce loading in the most cost-effective manner.

In 2023, NV Energy's demand response team began scheduling events in the DRMS using Oracle's Live Energy Connect "LEC" middleware that is an integral part of the Companies' on-going DERMS deployment. As part of Phase 1A of the DERMS project, the team implemented LEC to increase the security of scheduling events.

c. DR Coordination to Minimize the Incremental Cost of DERs

NV Energy continues to be focused on an Integrated Demand Side Management ("IDSM") format. IDSM programs are an effort to minimize the deployment costs of multiple DER technologies, thereby improving the cost-effectiveness of DSM programs and the customer experience. To date, the Companies' IDSM offerings have been focused on deploying DR infrastructure and device types that provide EE benefits or can be incrementally upgraded to provide additional EE savings and operational information. With improved coordination across customer programs, the IDSM format can be extended to DG systems, and thermal and electrical energy storage.

Since the current regulations require separate cost recovery mechanisms, the DRP goals of fostering improved coordination between existing programs and minimizing the incremental costs to deploy DERs cannot yet be fully attained. Nonetheless, NV Energy is leveraging both DSM and CE programs being under the same leadership to maximize incremental cost saving opportunities.

d. DER Support of Locational Benefits

The role of CE programs is aligned with EE and DR programs. Distributed generation systems such as solar PV and energy storage devices[49] displace traditional centralized generation, which must use the utility's electric grid to deliver electricity to customer sites. This displacement can

[49] Energy storage devices are included in the definition of generators in NV Energy's Rule 15, but only for the purposes of that tariff.

enable these DERs to relieve load constraints on the utility's electric grid and can help defer traditional wired capital upgrade costs by reducing peak loading. These DERs must be controllable and dispatched strategically to avoid increasing demand loading or disrupting the electric grid during peak loading hours. Mutual coordination between customers and the utility would facilitate optimal dispatch, making DG systems a viable NWA technology alternative.

The following are criteria to consider when utilizing DG systems within an NWA solution portfolio:

- Specific features of the utility feeders such as length, size, installed protection, voltage regulating equipment;
- Location of the DG systems on the feeder;
- The feeder's hosting capacity;
- Daily and seasonal feeder load shape compared to the DG systems' generation curve;
- Reactive power requirements and flows on the feeder; and
- Capabilities of the utility to communicate with the DG systems' advanced smart inverters and dispatch to adjust the real or reactive power.

e. Electric Vehicles and Electric Vehicle Infrastructure Coordination with DR

NV Energy considers a multi-strategy approach to prepare for successful vehicle-to-grid integration in the future. The tariffs and other program offerings described earlier that incentivize the adoption of EV technology, encourage off peak charging and facilitate vehicle-to-grid integration is one prong of this approach. Since the inception of NV Energy's EV programs, including EVID, ERTEP, and TEP, NV Energy has also prepared for future implementation of managed charging programs by requiring participating equipment that is compatible with NV Energy's DRMS and DERMS using Open ADR 2.0. As a part of these efforts, NV Energy engaged a vendor to perform a no-cost EV detection and managed charging trial. This trial is intended to help NV Energy identify customers who charge during peak periods more than 25 percent of the time. The connection to the vehicle via telematics enables data to be collected straight from the vehicle and in some cases allows the vehicle charging to be automated to align with TOU rates and flex response events. These customers can later be recruited into a future managed charging trial.

NV Energy is also testing the interoperability of multiple DER's on a single premise for both customer and grid benefit with the IRA Innovation Demonstration program. This program seeks to investigate ways of synchronously operating multiple DER's and the associated tariffs, which will help identify components of the tariffs that need updates to make this possible.

NV Energy is investigating how public charging equipment can provide locational net benefits to the grid. Some benefits include siting charging stations that are in Historically Underserved Communities. NV Energy will choose locations where there is available hosting capacity and access to NWA's.

f. Energy Storage Program Coordination with DR

A previous field demonstration was successful and led to the development of the technical interface for NV Energy to easily integrate with a fleet of BESSs from a single manufacturer. The demonstration consisted of 11 residential homes with existing grid-connected BESSs and provided incentives to interested customers who allowed access to participate in test DR events and remotely retrieve historical and real-time telemetry data. The primary objective of this field demonstration was to demonstrate the feasibility of peak demand reduction in the residential space by establishing communication between NV Energy and remote BESS management systems and testing direct load control through DR strategies.

Due to the success of the field demonstration, the Commission approved an expanded Energy Storage System DR Trial Measure in Docket No. 22-07004. The trial measures were approved for the purposes of testing the efficacy of energy storage as resources for demand response. NV Energy is actively recruiting customers who already installed energy storage devices on their property into the residential and commercial DR programs. Customers who have been enrolled are participating in NV Energy's demand response events that are scheduled during the summer of 2023. For more information, refer to the Residential Demand Response and Commercial Demand Response program data sheets in NV Energy's most recent Demand Side Management Update Report filing with the Commission.[50]

g. Coordination with HCA and NWA

DER technologies associated with NV Energy's existing Commission-approved programs are already embedded into several of the vital processes and analyses unique to the DRP. As noted above, the ability to reduce loading on distribution facilities through use of EE and DR technologies is already integrated into NV Energy's NWA Screening Analysis Tool. Although the NWA analyses presently include solar PV and BESS technology options assumed as NV Energy-owned front-of-the-meter ("FTM") assets, the Companies plan to investigate adding options that could include customer-owned aggregated solar PV and energy storage, optimally (but not necessarily) installed within the existing programs discussed above or new yet-to-be proposed or approved programs.

[50] Docket No. 23-06044, Joint Application, Narrative Sections 6 and 7.

As program-related DER assets continue to be installed on NV Energy's distribution systems, this generating and load-modifying capacity embedded into the power flow models used in the performance of the HCA studies will increasingly influence the results.

The symbiotic relationship between the DER technologies associated with NV Energy's existing Commission-approved programs and the goals and requirements of the DRP, although already established, will continue to grow and expand in a mutually beneficial manner for both NV Energy and its customers.

Section 7. Publicly-Accessible DRP Web Portal

The development, delivery of, and access and registration requirements for the initial version of NV Energy's publicly-accessible DRP web portal were discussed in the Companies' 2019 DRP filing.[51] The 2021 DRP discussed the additional data and functionalities that were added to the DRP web portal between that filing and the 2019 DRP filing. The web portal is accessible directly at https://drp.nvenergy.com (through Google Chrome and Microsoft Edge). For security and tracking purposes, users must register to access the results.

All the portal's functionality is explained in the DRP Web Portal User Guide which is downloadable from the DRP web portal login screen by clicking on "DRP UserGuide." The user guide is provided in **Technical Appendix DRP Update-7**. Recent updates to the data on the portal include updated HCA results files, distribution feeder load profiles, GNA Summary Table, LNBA Summary Table, Past Peaks Data, and Forecast Peaks Data files. All these files are downloadable from the portal.

[51] The DRP Web Portal is accessible directly at https://drp.nvenergy.com or from NV Energy's corporate public website www.NVEnergy.com by clicking on "Clean Energy" and "Distributed Resource Plan-Developer Portal" under the Resources heading on the bottom of that webpage. The portal must be accessed via the Microsoft Chrome or Edge web browsers and users must have the "Microsoft Authenticator" application on their smartphone or similar device.

Section 8. Continued Refinement of DRP Elements

Figure 18 in the 2019 DRP filing provided an initial gap analysis between NV Energy's then-current processes and tools as compared to those necessary to develop the DRP and advance it beyond its initial form and content. DRP-Table 54 in the 2021 DRP filing and DRP Update-Table 28 in the 2022 DRP Update filing provided updates of that gap analysis. DRP Update-Table 23 below provides a further update of this analysis.

DRP UPDATE-TABLE 23:
GAP ANALYSIS FOR DRP PROCESSES AND TOOLS

Area	Gaps	Status
Methodologies	Locational, granular DER forecasting methodology for multiple technologies	DER Forecasting and Valuation Toolset contractor selected and contract executed to develop methods and tool for forecasting all DER types in support of 2024 DRP filing.
	Methodology for monthly HCA update	Completed. Monthly HCA updates have occurred for the past three years. Refinement as needed.
	Further refinement of HCA method and criteria	Protection-related criterion not needed at present, Investigations of operational and reliability-related criteria, effects smart inverter capabilities, feeder exclusion criteria, and results accuracy scheduled over the next two years.
	Methodology for procurement process for NWA portfolio solutions	Investigation planned for "run" phase in approximately three years.
Software and Tools	Potential need for additional operational, monitoring, and control systems	First phase of DERMS completed with remaining implementation through 2026. Continuing targeted installation of intelligent line sensors.
	Potential need for DER forecasting software/tool	DER Forecasting and Valuation Toolset contractor selected and contract executed to develop methods and tool.
	Need for publicly-accessible web portal	Completed and updated monthly with HCA results data and annually with other data.

DRP UPDATE-TABLE 23 (cont.):
GAP ANALYSIS FOR DRP PROCESSES AND TOOLS

Area	Gaps	Status
Processes	Update of Rule 15 due to new IEEE Standard 1547-2018 and advanced inverter functionality	Rule 15 update presently planned for 2024.
	Further refinement of NWA techniques and process	General lead time established, leveraging of DER potential study and valuation methods to occur in 2024, monthly NWA process to begin in 2024, and investigation of cost-effective sourcing options planned in two to three years.
	Need for established cost-effective procurement sourcing process for NWA portfolio solutions	Investigation and implementation planned in two to three years.
	Process for monthly HCA updates	Completed. Monthly HCA updates have occurred for the past three years. Refinement as needed.
Timing and Coordination	Coordinated, integrated DER planning process with the utility	Interdepartmental coordination established. Roles will continue to be better understood and grow.
Stakeholder Engagement	Utility-led stakeholder engagement process	Bi-monthly stakeholder meetings to discuss improvements to the DRP based upon intervenor testimony in the 2021 DRP and 2022 DRP Update filings began in December 2022 and are anticipated to continue through the 2024 DRP filing.

Most of the above-identified items are addressed either directly or indirectly in the areas discussed below, but all have been addressed in some manner either during the development of this filing or are planned to be going forward.

The figures below generally depict recent activities since the filing of the 2022 DRP Update and those that NV Energy presently expects to undertake through the remainder of the "Jog" stage. Earlier phases of progress on each of the elements are not shown for brevity. The months shown are meant to reflect when the phase would be planned to be completed by.

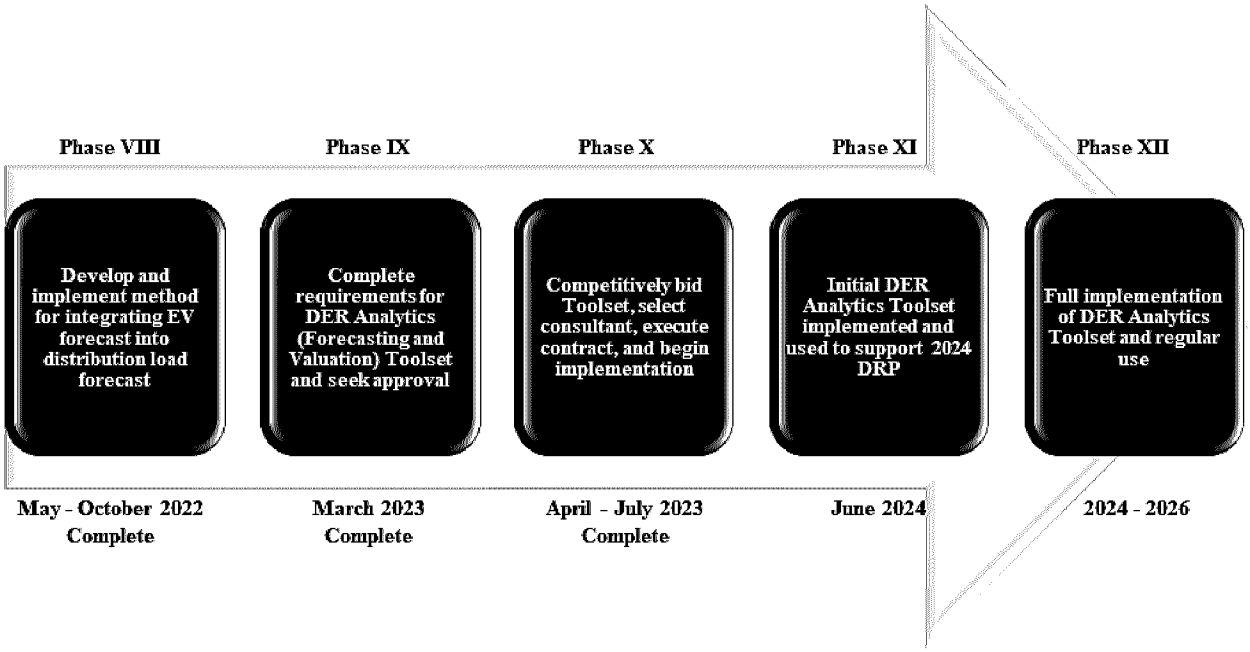
A. Load and Distributed Energy Resource Forecasting

Advanced, multi-scenario forecasting methods can aid in forecasting load and DER adoption at a granular level through development of a bottom-up forecast, as opposed to the top-down, system-level forecasting performed to support triennial IRPs. Advanced forecasting methods will need to

account for growth, customer adoption rates, customer consumption profiles, and DER profiles at a granular level (*i.e.*, more precise than the feeder level). This advanced forecasting would require new procedures and methodologies, and potentially, software investment.

DRP Update-Figure 11 below depicts the completed phases and expected load and DER forecasting.

DRP UPDATE-FIGURE 11:
LOAD AND DER FORECASTING REFINEMENT TIMELINE



Phase VIII

NV Energy's Distribution Planning department developed an initial method of incorporating the effect of residential EV load growth and forecast information into the peak load forecast for distribution feeders.

Phase IX

NV Energy completed the functional and technical requirements and scope of work for its DER Analytics Toolset and Potential Study effort in March 2023. Technical Appendix DRP Update-4 contains the scope of work for that effort.

Phase X

NV Energy issued a competitive Request for Proposals for the DER Analytics Toolset and Potential Study effort in March 2023, evaluated the proposals in April-May 2023, and executed a contract with Integral Analytics in July 2023 to begin work on the effort.

Phase XI

NV Energy expects the results of the DER Analytics Toolset and Potential Study effort to support the analyses in its DRP filing and inform its DSM Plan filing within its planned June 2024 Joint IRP filing.

Phase XII

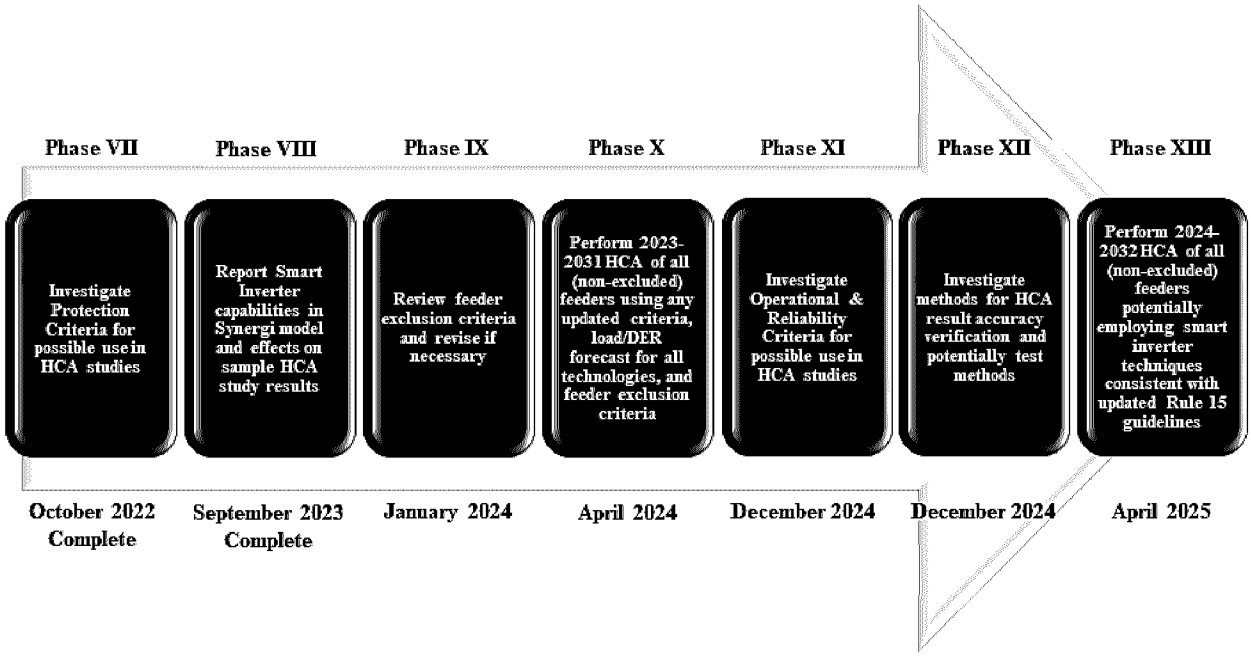
NV Energy and its consultants expect to continue to develop the tools associated with the DER Analytics Toolset and Potential Study effort potentially through 2026.

B. Hosting Capacity Analysis

NV Energy's HCA extends almost a decade into the future, with the hosting capacity of the feeder sections of the full feeder system updated annually in the first quarter of each year and a significant portion of the total distribution feeders in the system having their hosting capacity updated monthly the remainder of the year.

DRP Update-Figure 12 below depicts the completed phases since the 2022 DRP Update and the expected refinement of the Hosting Capacity Analysis.

DRP UPDATE-FIGURE 12:
HOSTING CAPACITY ANALYSIS REFINEMENT TIMELINE



Phase VII

NV Energy determined that, because reverse power flow at the feeder headend is not yet prevalent on the system (less than 10 feeders experienced notable reverse power flow at the feeder headend in 2021) and no operational or protection-related problems have been attributed to reverse power flow on the system, no hosting capacity limitations based upon protection-related criteria need be enforced at present.

Phase VIII

Currently, the model of NV Energy's distribution system in Synergi does not discreetly model the inverters associated with solar PV installations (or other inverter-based DER technologies). NV Energy understands that certain capabilities of smart inverters could potentially improve hosting capacity by addressing the limiting factor in the HCA for given feeder sections, particularly when that factor is voltage-related.

Ultimately, NV Energy's ability to model and utilize smart inverter capabilities in its studies will be dependent upon the inverter capabilities in Synergi. Current smart inverter modeling settings in the software include:

- Voltage trip;
- Frequency trip;

- Rising and falling ramp rate;
- Volt/VAR function; and
- Volt/watt function

The voltage and frequency trip settings provide the capability for the software to "trip off" the DER if the voltage or frequency in the software solution goes outside of established ranges. Both voltage support and limiting capabilities can be achieved through the Volt/VAR function that can model the injecting or absorbing of reactive power to help control the local voltage and keep it within its desired range. The Volt/watt function enables the software to ramp power down (curtail output) or up (allow increased power output up to the maximum capable output at that time) to help control the local voltage and keep it within its desired range.

NV Energy performed some very preliminary modeling using settings gleaned from Pacific Gas & Electric's Rule 21 and detected minimal changes in voltage on the feeders modeled, but more modeling is required and planned to truly determine what the effect on the hosting capacity of the feeder sections on NV Energy's feeders could be.

Phase IX

NV Energy recognizes that a notable portion of its distribution feeder system is redacted from the hosting capacity screens on the DRP Web Portal and therefore HCA results for those feeders are not available for viewing and download from the portal. The Companies will review the redaction criteria, attempting to align with other states and utilities where appropriate, while ensuring that appropriate confidentiality is maintained.

Phase X

As has occurred the past several years, the hosting capacity of the feeder sections of all distribution feeders will be updated in the first quarter of 2024. NV Energy anticipates that any forecasting data available from the Companies' DER Analytics Toolset and Potential Study effort at the beginning of 2024 will be incorporated into system model for this analysis.

Phase XI

Similar to protection-related criteria, the Companies will attempt to determine the need for and how limiting criteria associated with operating and reliability interests could be incorporated into the HCA.

Phase XII

Although great effort is expended in preparation for conducting HCA and in reviewing the results, ultimately, the proof of its usefulness in facilitating increased DER penetration on the distribution system in a cost-effective, safe and reliable manner is its verifiable accuracy in real circumstances going forward. The Companies anticipate investigating methods for verifying the accuracy of HCA results and potentially testing these methods.

Phase XIII

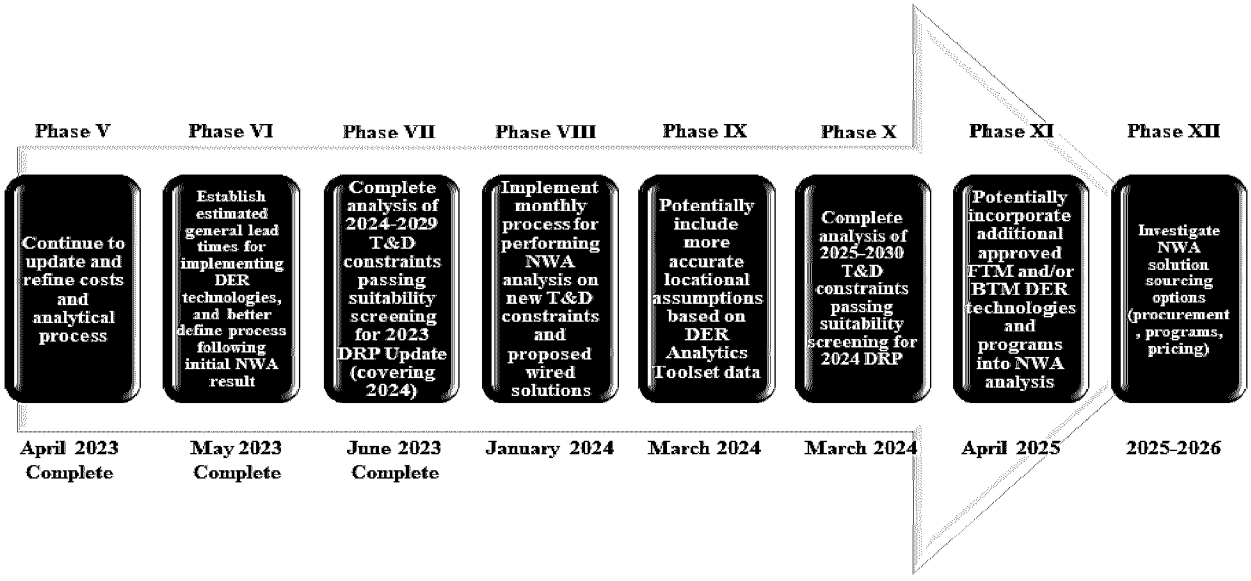
The Companies anticipate conducting the first quarter 2025 full-system HCA study with an updated feeder exclusion list, incorporating of smart inverter techniques and settings as feasible within the Synergi software and appropriate based upon information associated with the update of Rule 15, and any potential change in limiting criteria associated with operating and reliability interests.

C. Grid Needs Assessment/Non-Wires Alternative Analysis

Although NV Energy has been performing NWA analyses for both distribution and transmission system constraints and proposed traditional wired solutions for several years now, there are still improvements that can be made to this analysis process as the DRP moves along in its maturation process.

DRP Update-Figure 13 below depicts the completed phases since the 2022 DRP Update and the expected refinement of the Non-Wires Alternative Analysis process.

DRP UPDATE-FIGURE 13:
NON-WIRES ALTERNATIVE ANALYSIS REFINEMENT TIMELINE



Phase V

Relevant cost and financial data were updated prior to beginning the NWA analysis process. The Companies will continue to review the NWA Screening Analysis Tool to discover opportunities for improvement.

Phase VI

Intervenor testimony in the Companies' 2021 DRP filing recommended the development of estimated lead times necessary for implementation of NWAs based upon project and/or grid constraint characteristics.[52] NV Energy agreed with that recommendation[53] and the Commission directed the Companies to establish such lead times but did not specify a due date.[54]

Constraint characteristics can often determine which NWA technology or tariff option may be applicable as a potential solution or not (*e.g.,* the implementation of a targeted DR program alone may not be the best solution to a constraint lasting many hours over many consecutive days due to customer fatigue, increased opt outs, and potential complaints that could occur, or solar PV alone may not be the best solution to a constraint occurring in the evening or at night unless paired with storage). Project characteristics can be a main determinant in the capital cost that could be deferred and the implementation lead time required to meet the necessary in-service date (*e.g.,* a short feeder tie will likely be less costly and have a shorter implementation timeframe than a new substation and the associated transmission line service to it).

NV Energy believes that one of the lessons that has been learned by utilities attempting to implement NWA solutions is that the associated new and more complex technologies often require longer implementation lead times. Another is that focusing on or ramping up existing program offerings can be helpful in shortening lead time for the development and implementation of new technologies. The time required for revised or new tariff implementation as compared to the lead time between the analysis and when the solution must be implemented may also factor into the type of NWA technology that can realistically be part of an NWA portfolio solution. Conversely, constraints with longer lead times may allow for a broader range of NWA technologies in the solution portfolio.

Although the intervenor testimony focused on specific project and/or grid constraint characteristics, the Companies believe that the lead time to implement NWA portfolio solutions depends as much upon the type of DER to be employed in the solution and the scope of the capacity and energy reduction necessary to confidently defer a traditional wired capital upgrade project solution.

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[52] Docket No. 21-06001, Direct Testimony of Clair Valentine, Q&A 23.

[53] Docket Nos. 21-06001 and 21-06002, Prepared Rebuttal Testimony of Joseph Sinobio, Q&A 9.

[54] *Id.*, March 8, 2022, Corrected Modified Final Order at 138, para. 351.

While the characteristics of the constraints that NV Energy performs NWA analyses on can certainly create a variety of unique situations, the Companies believe that in general most situations will require a lead time of two to four years from identification, characterization, analysis, decision-making, through solution implementation to occur. The Companies are actively working to identify opportunities sooner in order to ensure adequate lead time to implement cost-effective NWA solutions.

Phase VII

Although this 2023 DRP Update covers only 2024, in June 2023 the Companies completed NWA analyses on forecasted grid constraints in the 2024 through 2029 timeframe consistent with its established annual process. This consistent process (and the process improvement discussed in Phase VIII below) helps to ensure adequate lead time to develop and implement NWA solutions should the analyses support that option.

Phase VIII

Similar to its monthly process of updating the hosting capacity of selected distribution feeders, in 2024 the Companies expect to establish a monthly process of identifying newly-proposed traditional wired capital upgrade projects in need of NWA analysis and previously-proposed projects that have had changes to them that warrant an update to a previously-performed NWA analysis. Initially, the focus will be on constraints and associated capital projects within six years beyond the present year, but once this process has been established the Companies expect to expand the timeframe to 10 years beyond the present year, which would be in line with NV Energy 10-year capital planning timeframe.

In addition to flagging newly-proposed traditional wired capital upgrade projects, the expected process would note changes in the in-service date, estimated cost, and load forecast associated with previously-proposed projects to generate the list of projects requiring NWA analysis for that month.

Performing NWA analysis as soon as practicable and earlier in the lifecycle of a proposed traditional wired capital project could help identify opportunities earlier and provide improved lead time for the potential implementation of an NWA portfolio solution to an identified system constraint.

Phase IX

The Companies expect the DER market potential data gathered in the DER Analytics Toolset and Potential Study effort to enable more accurate determination of the capacity potential of certain DER technologies in certain locations, allowing a movement away from some general assumptions utilized thus far in NV Energy's NWA analyses. This should provide a better opportunity for cost-

effective NWA portfolio solutions to be determined but also introduce an improved measure of realism into the analysis.

Phase X

In support of the planned June 2024 filing of its DRP as part of its Joint IRP and in accordance with the applicable regulation, the Companies will complete NWA analyses on forecasted grid constraints in the 2025 through 2030 timeframe consistent with its established annual process.

Phase XI

Dependent upon the Companies' proposed offerings in its planned June 2024 DSM plan filing as part of its Joint IRP and subsequent Commission review and approval, NV Energy expects to determine if new approved DER technology and/or program and tariff options can be integrated into its NWA analysis, potentially for both BTM and FTM offerings.

Phase XII

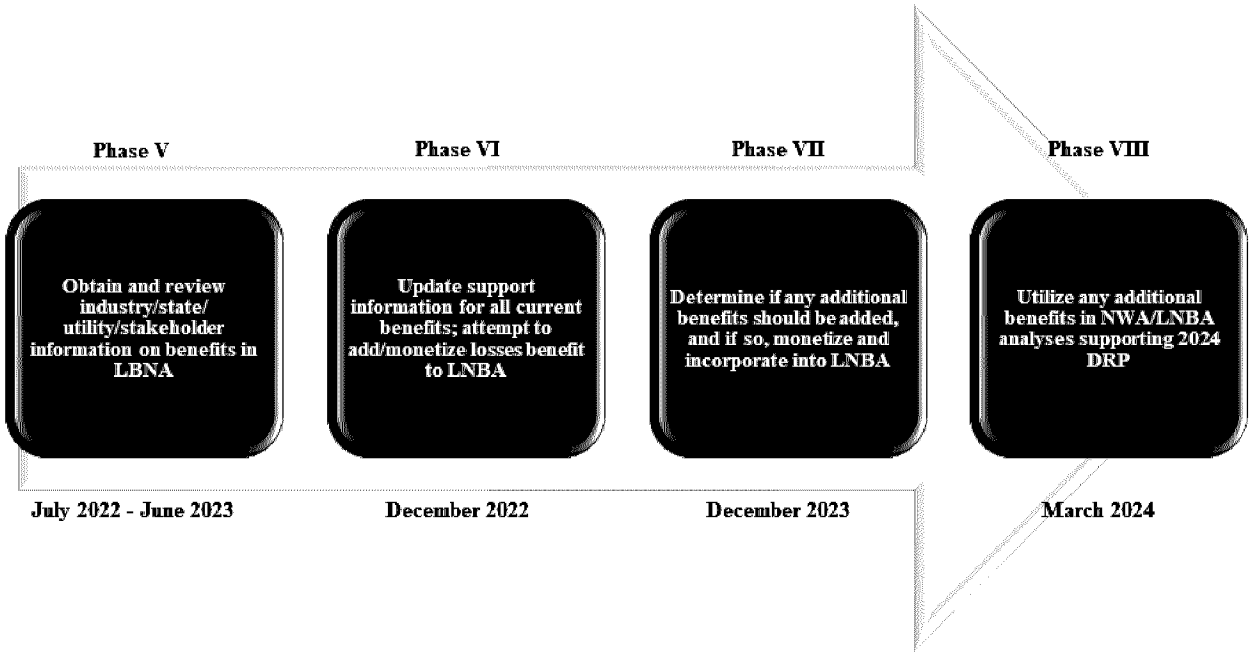
The Companies will investigate the different sourcing options available for NWA solutions and endeavor to determine which option(s) may best suit given situations.

D. Locational Net Benefits Analysis

One of the more unique aspects of the integration of DERs on the electric system is their ability to potentially provide benefits at both the system and local levels.

DRP Update-Figure 14 below depicts the completed phases since the 2022 DRP Update and the expected refinement of the Locational Net Benefits Analysis.

DRP UPDATE-FIGURE 14:
LOCATIONAL NET BENEFITS ANALYSIS REFINEMENT TIMELINE



Phase V

NV Energy completed the functional and technical requirements and scope of work for its DER Analytics Toolset and Potential Study effort in March 2023. Technical Appendix DRP Update-4 contains the scope of work for that effort, which contains requirements for DER valuation.

Phase VI

NV Energy issued a competitive Request for Proposals for the DER Analytics Toolset and Potential Study effort in March 2023, evaluated the proposals in April-May 2023, and executed a contract with Integral Analytics in July 2023 to begin work on the effort.

Phase VII

The Companies will review DER valuation information and recommendations from its consultant and determine which additional benefits may be added to its LNBA.[55]

[55] The "National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources" report published in August 2020 by the National Energy Screening Project will be used as a source of potential DER benefits.

Phase VIII

If added to the LNBA, any additional benefits would be part of the NWA analyses performed in support of the DRP filing within the Companies' June 2024 Joint IRP filing.

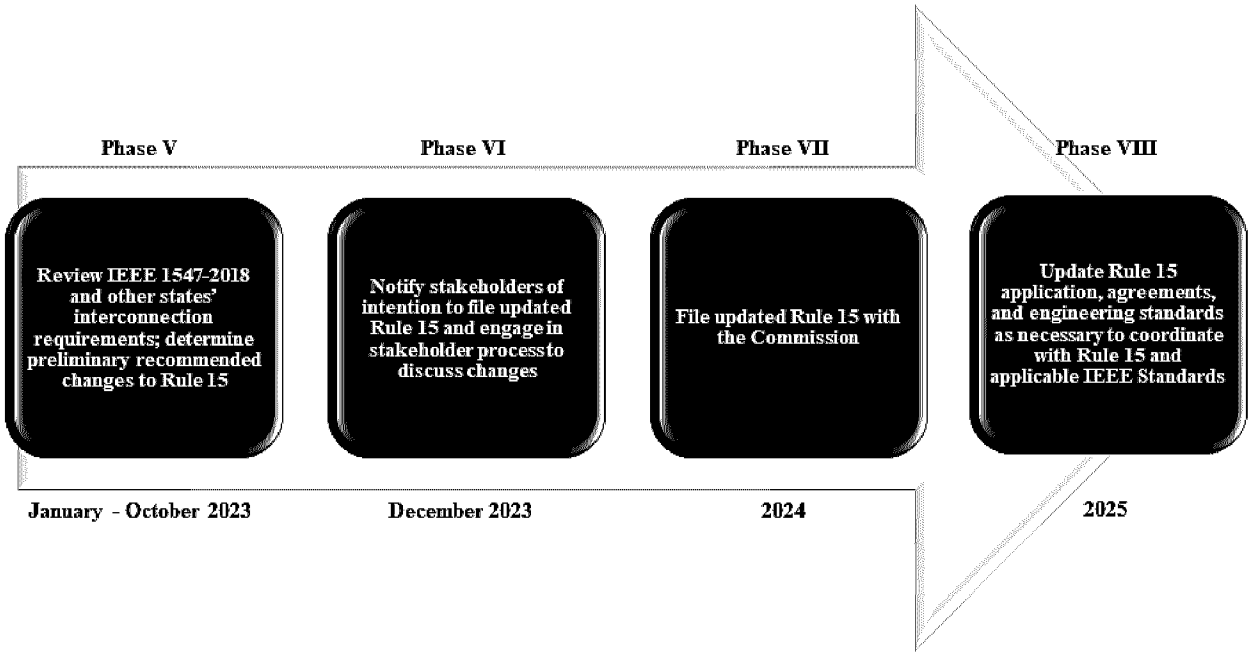
E. DER Interconnection

NV Energy's Rule 15 governs the interconnection of DERs of 20 MW capacity or less seeking to connect to the Companies' distribution systems. Rule 15 outlines the interconnection process, technical operating and metering requirements, and testing and certification criteria for distributed generators, including energy storage devices. NV Energy utilizes Clean Power Research's PowerClerk software to facilitate the interconnection process of net energy metering installations, mainly private solar PV. Depending on their size, non-net energy metering DG interconnections may be required to submit a different application to interconnect under Rule 15.

NV Energy understands the importance of ensuring that the DER interconnection process includes and balances the expectations of applicants for a clear and expeditious process and the Companies' mandate to ensure the safe functioning of its electric system with ever-increasing DER penetration and variable power flows.

DRP Update-Figure 15 below depicts the completed phases since the 2022 DRP Update and the expected refinement of the DER Interconnection process.

DRP UPDATE-FIGURE 15:
DER INTERCONNECTION REFINEMENT TIMELINE



Phase V

As has been stated in previous DRP filings, NV Energy's Rule 15 is due for a top-to-bottom review and updating to incorporate any appropriate changes from the updated IEEE 1547-2018. The Companies are engaged in reviewing the DER interconnection requirements in other states and gathering recommended changes to Rule 15.

Phase VI

As has been the case in other states, NV Energy understands that stakeholders have a vested interest in its rule governing DER interconnection and would expect to be part of the updating process sooner rather than later. The Companies intend to notify stakeholders of their intention to file an update of Rule 15 with the Commission, and to best facilitate this process, plan to initiate a stakeholder process to discuss desired changes to the rule by the end of 2023.

Phase VII

At the conclusion of the stakeholder process discussing changes to Rule 15, the Companies intend to file an updated rule with the Commission and request approval of such in 2024.

Phase VIII

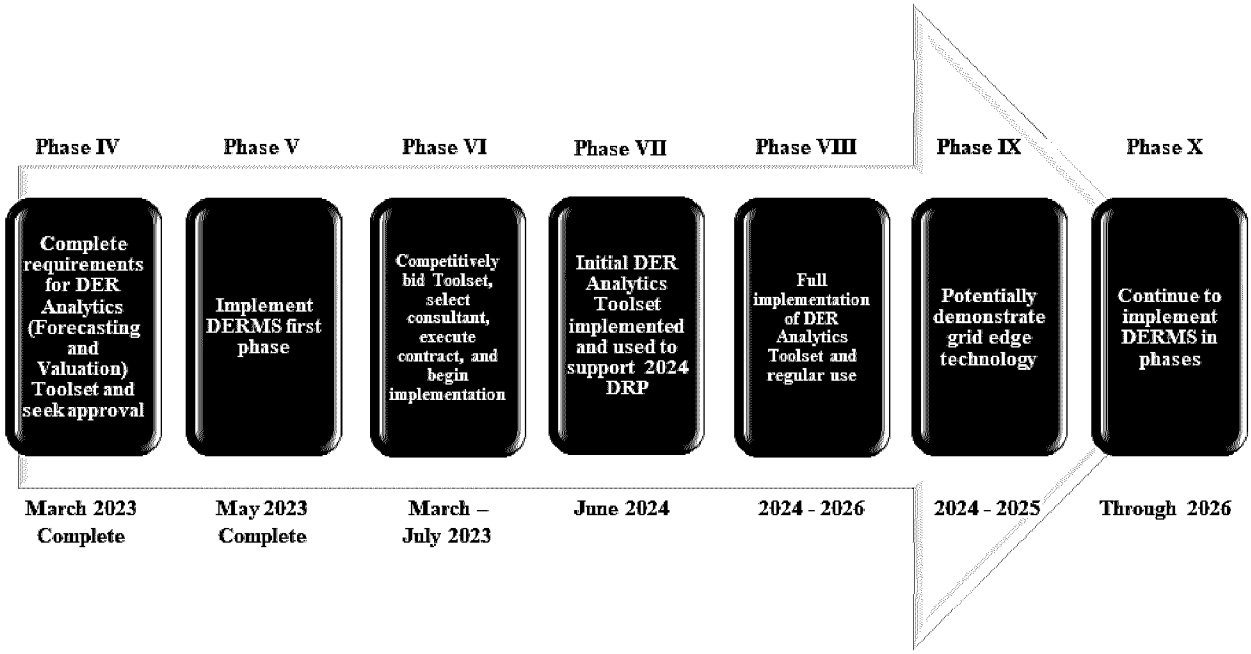
Once an updated Rule 15 has been approved by the Commission, the appropriate internal application, agreements, and standards should be reviewed and updated to ensure coordination with the rule and applicable IEEE standards.

F. Tools, Systems, or Technologies

NV Energy continues to consider new tools, systems, and technologies to more efficiently complete the analyses unique to the DRP and manage existing and future DER installations.

DRP Update-Figure 16 below depicts the completed phases since the 2022 DRP Update and the expected refinement of Tools, Systems, or Technologies.

DRP UPDATE-FIGURE 16:
TOOLS, SYSTEMS OR TECHNOLOGIES REFINEMENT TIMELINE



Phase IV

NV Energy completed the functional and technical requirements and scope of work for its DER Analytics Toolset and Potential Study effort in March 2023. Technical Appendix DRP Update-4 contains the scope of work for that effort.

Phase V

The first phase of NV Energy's DERMS project was placed in-service in May 2023. Section 9.A below provides a status of the project.

Phase VI

NV Energy issued a competitive Request for Proposals for the DER Analytics Toolset and Potential Study effort in March 2023, evaluated the proposals in April-May 2023, and executed a contract with Integral Analytics in July 2023 to begin work on the effort.

Phase VII

NV Energy expects the results of the DER Analytics Toolset and Potential Study effort to support the analyses in its DRP filing and inform its DSM Plan filing within its planned June 2024 Joint IRP filing.

Phase VIII

NV Energy and its consultants expect to continue to develop the tools associated with the DER Analytics Toolset and Potential Study effort potentially through 2026.

Phase IX

NV Energy is working with vendors to understand current grid edge device offerings and learn how they could be integrated into the system, maximize the integration of DERs, and ensure safe and reliable service to customers. The Companies are considering demonstrating at least one of these technologies.

Phase X

NV Energy will implement DERMS in phases over the course of several years. Section 9.A below provides a status of the project.

Section 9. Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Energy Resources

In accordance with NAC 704.9237(2)(d), this section discusses any additional (incremental) investment necessary to cost-effectively integrate DERs into the distribution planning process.

With successful EE, DR, and Renewable Energy Generations Programs in place for many years, the Companies have extensive experience with DER. Several existing, recently developed and utilized, and future tools will assist in tracking, analyzing, managing, and understanding the impacts of DERs on the Companies' electric grid, enabling additional DER penetration in a safe and reliable manner.

NV Energy is developing new systems to properly monitor, control, and deliver new value streams from an expanded set of DERs in a scalable and extensible fashion. Specifically, the Companies are developing the foundational technology required to efficiently manage a growing set of DERs through implementation of a centralized DERMS system to be complemented by DOE-funded grid-edge systems and applications as discussed in the next two sections.

A. Distributed Energy Resource Management System

NV Energy requested Commission approval to investigate and implement a DERMS in its 2021 DRP filing in Docket No. 21-06001.[56] The Commission approved the Companies' request in its Corrected Modified Final Order dated March 8, 2022.[57] NV Energy has since negotiated full DERMS functional specifications with Oracle Utilities. The parties have signed related contract and task order documentation. The contract documentation confirms the vendor budget estimates submitted in Docket No. 21-06001 and the completion of the first task order enabled the launch of detailed solution design workshops for the first several releases of DERMS that will replace the existing DRMS.

The DERMS is planned to be comprised of a set of tightly integrated Oracle Utilities solutions that will be configured and customized to meet the negotiated functional specifications. Consequently, the DERMS is referred to as a "system of systems." Key products that will be used to implement DERMS include:

- DERMS Module of Oracle Network Management System ("Oracle NMS") will be implemented at NV Energy in parallel with the DERMS project in order to upgrade and enhance the Companies' current ADMS. The DERMS project will leverage and incrementally implement a new module within Oracle NMS that will function as the "Operational DERMS" component of the DERMS system of systems. This is now branded

[56] Joint Application, Vol. 2 at 27; Vol. 13, Section 9.B.
[57] At 153-54, para. 385-88.

as "GridEdge DERMS". This component will focus on demand response event dispatch strategy creation through advanced optimization of the individual control capabilities of each participating DER. The optimization will be cognizant of the near-real-time operating conditions and power flow modeling of the distribution system. Event dispatch strategies will be dynamically formulated to provide load shed and load shaping events to support both distribution and system-level operations via economic, emergency, and reliability events. Operational DERMS will provide DER situational awareness to the ADMS platform and coordinate DER control with other ADMS modules implementing advanced applications including VVO/CVR and Fault Location, Isolation, and Service Restoration ("FLISR").

- Oracle Utilities Device Asset Management ("DAM") (formerly known as Oracle Device Management or "ODM") is a specific product implementation that will be created to serve as the foundation of "Business DERMS." This module will focus on customer, program, and device asset management functions. Customers, customer service agents, field service agents, and program managers will all interact with Business DERMS to enable business process flows for program enrollment, program support, device installation, provisioning, and service. Business DERMS will support business processes that utilize enrollment data and event performance calculations to help process and track customer incentives. It will be integrated to the billing system as well as to a new company messaging and notification system (*i.e.,* Oracle Responsys) to notify customers of demand response events such as PowerShift Smart Thermostat events and CPP events.

- Oracle Utilities Analytics Insights ("OUAI") is a software platform that enables the configuration of advanced analytics use cases primarily for predictive analytics using high volume, high velocity data. The DERMS utilization of OUAI will focus on load forecasting, and DER device availability forecasting (*i.e.*, availability and capability to participate in events). The module will also be used to support measurement and verification ("M&V") and financial settlement calculations for certain programs. OUAI allows the implementation of artificial intelligence via machine learning tools to improve load and DER availability forecast accuracy.

- Oracle Utilities Analytics Service ("OAS") Dashboard is a software component that will largely focus on descriptive analytics. It will enable robust status reporting to provide program managers with the metrics needed to execute and improve business processes across a wide range of process flows.

- Oracle Live Energy Connect ("Oracle LEC") is a system that will serve as an operational service bus, or middleware, to transmit data between software systems in a highly secure manner. Data exchange will occur between back-office enterprise systems and DER devices in the field. DERMS communications with DER devices in the field could occur directly through broadband internet or utility field area networks, but, in most cases, communications will occur through third-party device clouds that supervise vendor

specific device fleets. Oracle LEC will support a set of industry protocols to securely enable communications with a variety of devices and third-party device clouds.

NV Energy and Oracle moved the first release of DERMS into production on May 22, 2023. This release implemented the Oracle LEC product and transitioned DRMS device communications and control for the current fleet of DR and DER assets from utilization of existing middleware to an upgraded software and networking architecture that improved the security of device communications. The core DRMS has continued to operate and issue DR events throughout the summer of 2023. With only a few minor bugs discovered and quickly fixed, the upgraded Oracle LEC architecture has successfully supported all demand response events so far. The NV Energy and Oracle DERMS teams continue to work on detailed design for a second software release that targets implementation of DAM, OUAI, OAS Dashboard, and a basic version of Oracle NMS that includes the GridEdge DERMS Module. This second release was originally targeted for the first quarter of 2024 to support full replacement of DRMS; however, the complexity of the design process has extended the design phase and pushed development and testing further into 2024. The most likely scenario at the time of writing this narrative is that DRMS would be replaced before the start of the 2025 load control season. It would then be extended to support additional DER programs, devices, and communication protocols with a major 2026 release. Design, build, and release planning will continue to evolve as the parties work through detailed design for the most complex of the new functionalities related to operationalizing and co-optimizing new grid services across multiple DER types in concert with distribution system operations.

B. Department of Energy Grid Services Grant Project

NV Energy requested Commission approval to participate in a United States Department of Energy ("DOE") Grid Services Set ("GSS") Grant project in its 2021 DRP filing in Docket No. 21-06001.[58] The Commission approved the Companies' request in its Corrected Modified Final Order dated March 8, 2022.[59] NV Energy and project partners University of Nevada Reno ("UNR"), University of Nevada Las Vegas ("UNLV"), and Evolution Networks continue to work on this project after completing the first Budget Period (BP1) and receiving funding authorization and continuance approval from DOE to move into the second budget period (BP2).

BP1 was completed on January 31, 2022, after DOE granted the project team a six-month no cost extension. BP2 work began on February 1, 2022. Due to the complexity of the project, the team was granted a project extension for BP2 through the end of 2023.

The second budget period is primarily a software development and testing phase, with software components residing at various layers in a distributed communications and control architecture (DCA) in a home automation gateway or DER premise gateway, in the cloud at Amazon Web

[58] Joint Application, Vol. 2 at 27; Vol. 13, Sections 9.C and 10.H.
[59] At 159-60, para. 401-04.

Services, and in Beltway Substation with data integration to NV Energy backoffice systems. The software in the DCA will leverage a 1 MW/4 MWh BESS at Beltway Substation. NV Energy project management, engineering, and construction teams successfully completed installation and commissioning of the Beltway BESS, which was moved into operation on April 29, 2023. The BESS is currently operating on pre-configured schedules and is now available for grid services testing to support development of the DCA.

During BP2, the project team is working to complete 13 major deliverables described in DRP Update-Table 24 below.

DRP UPDATE-TABLE 24:
DOE GSS GRANT – BP2 MILESTONE DELIVERABLES UPDATE

No.	Task Title	Task Description
2.9.1	Hardware-in-Loop ("HIL") Testbed Checklist	This completed task verified commissioning and operation of the UNR HIL testbed - a testing and simulation environment in the power engineering laboratory that integrates software simulation including real-time digital simulation units with hardware components including smart inverters, and grid-edge DER gateways.
2.9.2	DCA Test Platform Checklist	This completed task consisted of complementing the HIL Testbed in Reno with a Las Vegas DER testing laboratory focused on simulating premise devices and connecting both labs to an Amazon Web Services ("AWS") cloud development environment.
2.9.3	DER Aggregation Model – Test Results	This ongoing task includes developing software in the cloud layer that ingests and processes grid services availability forecasts from DERs as modified and improved by leveraging historical grid services performance data.
2.10.1	Grid Service Set (GSS) – Test Results	This ongoing task includes building out software, processes, and grid service tariff rider approaches for distribution and transmission level capacity management, energy arbitrage, phase balancing, voltage support, and frequency regulation services from DER aggregations.
2.11.1	AI Agent – Test Results	This ongoing task includes building out digital twin software models of customer premise energy consumption and four DER asset types including solar PV systems, smart thermostats, grid-interactive water heaters, and batteries.
2.12.1	Co-optimization – Test Results	This ongoing task includes building out software that determines optimal dispatch instructions for DER devices providing one or more of the services in the GSS

2.13.1	Energy Storage - as-a-Service ("ESaaS") – Test Results	This ongoing task includes building out software, processes, and service approaches for ESaaS which allows customers to economically lease or purchase a remote block of battery energy storage in a manner that reduces their net cost of managing electricity consumption.
2.14.1	Blockchain & Smart Contract – Test Results	This ongoing task includes building out software and processes related to two primary use cases of open-source blockchain technology: DER Asset management; and audit of grid services transactions.
2.15.1	DCA Hardware – Performance Reports	This task includes verification and reporting to DOE that the Beltway BESS and DER Premise Gateways have been developed and tested.
2.15.2	End-to-End Integration – Test Reports	This task will test communication and control pathways across the full DCA.
2.15.3	Measurement & Verification (M&V) SOW	This mostly completed task involves contracting for independent 3rd party M&V of the load impacts of the field demonstration.
2.15.4	Demonstration Readiness Checklist	This ongoing task includes expanding and refining the field demonstration plan along with verification that pre-requisites have been met to launch a field demonstration. It also includes additional primary market research to inform product approaches and customer messaging.
2.16.1	Dissemination and Outreach	The project team has largely completed this task and has provided copies of academic publications describing the project as evidence of meeting DOE's requirement for knowledge dissemination.

DRP Update-Table 25 below provides an updated high-level schedule for the DOE GSS Grant project.

DRP UPDATE-TABLE 25:
DOE GRID SERVICE GRANT SCHEDULE UPDATE

Budget Period	Status	Start/End Dates	Status Summary
BP1	**Completed**	August 1, 2020- January 31, 2022	**Research Phase** All milestones were completed and submitted. BP2 continuance application approved by DOE.
BP2	Ongoing	February 1, 2022- December 31, 2023	**Development Phase** • Team is currently developing and testing software code and developing more detailed demonstration plans. Test and validation results must be provided to DOE along with a detailed demonstration plan and evidence of demonstration readiness. • Substation BESS for Beltway Substation was moved into operation on April 29, 2023.
BP3	Not yet authorized by DOE	January 1, 2023- December 31, 2024	**Demonstration Phase** Implementation and supervision of customer field demonstration with measurement and verification of impacts, and operational research to revise and improve software algorithms and services as necessary.

Section 10. Pilot and Demonstration Projects

Notwithstanding the fact that EE and DR have been employed on NV Energy's system for many years, non-wires DER solutions on the distribution system directed at addressing specific constraints and deferring traditional wired solutions are new to NV Energy, as well as to many other utilities currently in various stages of testing or deploying these technologies. The Companies support a measured approach, but also advocate moving forward to vet these technologies to ensure that they can accomplish their goals and provide their expected benefits and do so in a safe and reliable manner under real-world conditions.

A. Non-Wires Alternative Analysis

As described above in Section 6.B.2.b, following on the success of the geo-targeted DR program demonstrations at the Village Substation in 2019, the Northwest Substation in 2020, and the Leavitt Substation in 2021, NV Energy initiated and successfully implemented a similar demonstration at the Bicentennial Substation (in Las Vegas) in the summer of 2022. Although there were no forecasted distribution constraints on the feeders or substation transformers at the Bicentennial Substation in 2022, there is a planned traditional wired capital upgrade project entitled Bicentennial Bank 3 to be installed by June 1, 2024. This demonstration achieved its purpose by again demonstrating the ability to measurably reduce peak loading on distribution substation transformers, as evidenced by the results below.

Eleven DR events were called between August 1, 2022, and September 10, 2022, on the Bicentennial Substation on 1,210 customer premises comprised of 668 Ecobee users and 542 EcoFactor users. DRP Update-Table 26 below provides the days, high temperatures, event times, and calculated kW reductions and snapback amounts for the events (negative value indicates a decrease in load; positive value indicates an increase in load).

DRP UPDATE-TABLE 26:
SUMMER 2022 DR EVENTS DATA
ON BICENTENNIAL SUBSTATION

Date	Max Temp (°)	Event Time	1st Hour kW Reduction	2nd Hour kW Reduction	1st Hour kW Snapback	2nd Hour kW Snapback
8/3/2022	104	15:00 - 17:00	-1704.2	-389.2	480.7	68.4
8/24/2022	102	15:00 - 17:00	-1353.8	-67.8	567.2	182.9
8/29/2022	102	15:00 - 17:00	-1752.0	-677.6	440.6	-207.4
8/30/2022	107	15:00 - 17:00	-1638.6	-645.3	502.9	-136.2
8/31/2022	109	15:00 - 17:00	-1902.5	-745.6	484.6	-118.5
9/1/2022	109	18:00 - 20:00	-1996.8	-189.7	948.3	550.8
9/2/2022	108	18:00 - 20:00	-1870.9	-263.5	774.6	388.0
9/5/2022	108	18:00 - 20:00	-1602.4	-81.9	976.0	549.6
9/6/2022	110	18:00 - 20:00	-1767.2	-276.8	826.7	571.1
9/7/2022	107	18:00 - 20:00	-672.2	-29.0	479.1	376.8
9/8/2022	105	18:00 - 20:00	-525.7	187.6	512.2	364.9

As shown in the table, a maximum estimated load reduction of 1,997 kW occurred on September 1, 2022.

B. Locational Net Benefits Analysis

Activities within the context of the DOE Grid Service Grant project relate to this concept and are discussed above in Section 9.B.

C. Localized Substation-Level DR Events

During the summers of 2021 and 2022, NV Energy created geo-targeted loading reduction DR strategies for several substation "hot spots."[60] This strategy is again being employed for the summer of 2023 with the participating substations shown in DRP Update-Table 27 below. The purpose of these strategies is to reduce the loading on the transformers and/or distribution feeders at the substations when the temperature is above 110 degrees in response to ad hoc requests from NV Energy's Distribution Operations department. These events support the maintaining of service reliability in specific geographic areas and avoided potential facility overloading.

[60] NV Energy defines a "hot spot" as a distribution facility that is forecasted to have loading, phase balancing and/or voltage outside normal parameters under normal operating conditions, where a solution may or may not be completed in time to prevent the undesirable condition.

DRP UPDATE-TABLE 27:
2023 SUBSTATIONS FOR HOT SPOT STRATEGY

Substation Name
Artesian
Cabana
Gilmore
Green Valley
Haven
Leavitt
Miller
Mountain's Edge
North Las Vegas
Robindale
Tomsik
Washburn
Winterwood

Section 11. Specific Requests for Commission Approval

A. NV Energy Requests for the Commission

Based on the information provided in the above Narrative, as well as the testimony and the information provided in the Technical Appendices attached hereto, NV Energy requests that the Commission approve the 2023 DRP Update as compliant with NAC 704.9239 and determine, pursuant to NAC 704.9241 and 704.9494(5), that the elements contained in NV Energy's 2023 DRP Update continue to be prudent. The Commission may make that determination based on the following:

1. The summary describing the results of the April 27, 2023, stakeholder meeting discussed in Section 2.D.1 of this DRP Update is in compliance with NAC 704.9237(3)(e);
2. The load and DER forecasting methods as discussed in subsections 3.A.1 and 3.B.1 of this DRP Update are prudent and in compliance with NAC 704.9237(2)(f), subject to the request to waive certain aspects of that regulation as noted below in Section 11.B;
3. The HCA methods as discussed in subsection 3.A.2 of this DRP Update are prudent and in compliance with NAC 704.9237(3)(b), subject to the request to waive certain aspects of that regulation as noted below in Section 11.B;
4. The GNA methods for the distribution system as discussed in Section 3.A.3 of this DRP Update are prudent and in compliance with NAC 704.9237(3)(a). This includes the following elements:
    a. The identification of distribution constraints and projects as discussed in subsection 3.A.3.a.;
    b. The NWA analyses as discussed in subsection 3.A.3.b.;
    c. The LNBA as discussed in subsection 3.A.3.c.; and
    d. The traditional wired upgrade projects and NWA solutions recommendations as discussed in subsection 3.A.3.d.;
5. The GNA methods for the transmission system as discussed in Section 3.B.3 of this DRP Update are prudent and in compliance with NAC 704.9237(3)(a). This includes the following elements:
    a. The identification of transmission constraints and projects as discussed in subsection 3.B.3.a.;
    b. The NWA analyses as discussed in subsection 3.B.3.b.;
    c. The LNBA as discussed in subsection 3.B.3.c; and

d. The traditional wired upgrade projects and NWA solutions recommendations as discussed in subsections 3.B.3.d.;

6. The LNBAs for the distribution and transmission systems as discussed in subsections 3.A.3.c and 3.B.3.c. of this DRP Update have been prudently performed in compliance with NAC 704.9237(2)(a);
7. The update to the TEP detailed in Section 4 is in compliance with the requirements of NAC 704.9239 and NAC 704.9237 (3)(g)(1), as adopted through LCB File No. R005-22 regulation.
8. The NWAs and utility infrastructure upgrade solutions recommendations discussed in Sections 3.A.3.d and 3.B.3.d of this DRP Update are prudent and in compliance with NAC 704.9237(3)(c);
9. The identification of barriers to the deployment of DERs discussed in Section 5 of this DRP Update is in compliance with NAC 704.9237(2)(e);
10. The summary explaining how DERs have affected the need for supply-side resources in the resource planning process discussed in Section 6.A of this DRP Update is in compliance with NAC 704.9237(3)(d);
11. The identification of existing programs approved by the Commission that address the deployment of DERs and the methods of effectively coordinating these programs to maximize the locational benefits and minimize the incremental costs of DERs discussed in Section 6.B of this DRP Update is in compliance with NAC 704.9237(2)(c);
12. The development and deployment of a publicly-accessible web portal that provides maps and accessible electronic data discussed in Section 7 of this DRP Update is in compliance with NAC 704.9237(5);
13. The identification of any incremental utility investment or expenditure necessary to integrate cost-effective distributed resources as discussed in Section 9 of this DRP Update is in compliance with NAC 704.9237(2)(d); and
14. The Technical Appendix submitted with this DRP Update, which includes Technical Appendices DRP Update-1 through DRP Update-7, is in compliance with NAC 704.9237(3)(f).

B. NV Energy Requests for Waivers of Nevada Administrative Code Requirements

Through its best efforts, NV Energy was able to complete virtually all the requirements contained in the applicable sections of NRS and NAC related to the DRP, with the exception of the items listed below. The Companies request a waiver of certain requirements of the regulations as follows:

- NAC 704.9237(2)(f) states that the DRP must *"Be developed by a utility using a forecast of net distribution system load and distributed resources. The forecast must be for a period*

of not less than 6 years, beginning with the year after the distributed resources plan is filed. The net distribution system load and distributed resources forecast will include system, substation and feeder level net load projections and energy and demand characteristics for all distributed resource types." NV Energy utilized the latest available net distribution feeder, substation transformer, and transmission forecasts to determine the constraints on the T&D systems. However, all distributed resource types as defined in NAC 704.90583 are not yet represented in those forecasts. The Companies have disaggregated system-level private solar PV forecasts down to the substation and feeder levels, have received an updated EV forecast by census block, and are in the process of developing a method to segregate and allocate the load associated with existing and future EV charging to individual feeders. Also, the Companies have begun developing the requirements for a DER Forecasting and Valuation solution that would ensure that all DER types are forecasted and is presently targeting this effort to be completed in a timeframe that would support the DRP filing that would occur on or before June 1, 2024 (see Section 8.A).

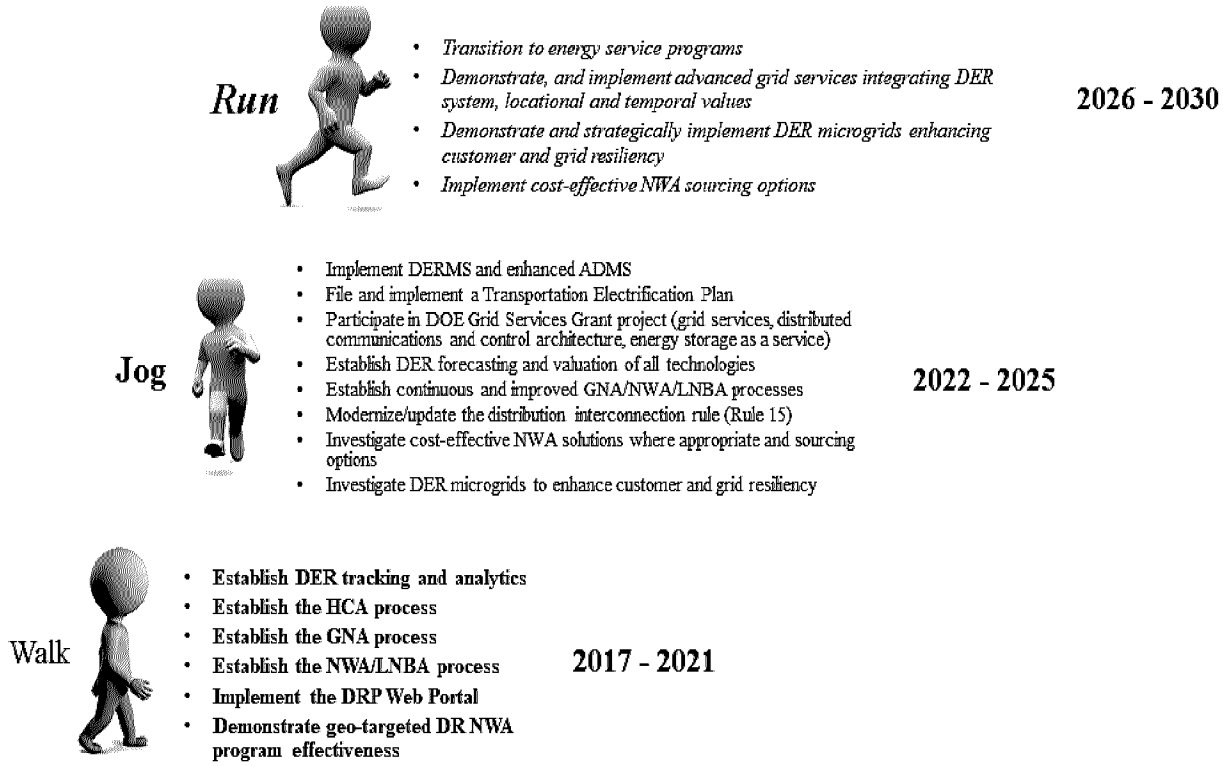
- NAC 704.9237(3)(b) states that the DRP must include a hosting capacity analysis of the distribution system evaluated *"under normal conditions and planned and unplanned contingency conditions."* The Companies have begun discussing the issue of performing HCA under contingency conditions internally and initially concluded that any contingencies analyzed would need to be limited in scope to ensure that the number of cases analyzed do not create an untenable situation in terms of being able to complete the analysis, especially considering that the monthly update and annual full-system update processes already take an entire month and an entire quarter to be completed, respectively, with current processes and resources. NV Energy also is investigating how other utilities may be approaching this issue to ascertain if there are any techniques that can be applied to ensure that the analytical process would not be overburdened by the addition of contingency conditions.

Section 12. View Moving Forward

Although this 2023 DRP Update is NV Energy's fourth filing of either a full DRP or an update, the methods employed to meet the regulatory requirements of the plan continue to evolve and be refined and likely will through the end of this decade. The "walk-jog-run" philosophy adopted as part of the development of the DRP and supported by the Commission necessitates additional information to provide some clarity on generally where along that evolutionary curve the DRP as a whole resides and a current outline for continuing to refine certain elements of the DRP (refer also to Section 8).

DRP Update-Figure 17 below represents the Companies' attempt to clarify what will certainly be a path that will ultimately differ looking back than perhaps it was initially conceived and should not be considered as a commitment on the part of the Companies to perform or achieve all the activities shown. The figure illustrates activities within the DRP's "walk-jog-run" philosophy. Components in bold font indicate that they have been completed and are in practice ("Walk"), those in normal font are currently being implemented, are planned for implementation, or are being considered for implementation ("Jog"), and those in italic font have not yet begun and represent potential future activities that, once completed, would represent the conclusion of the specific efforts to refine and evolve the DRP ("Run").

DRP UPDATE-FIGURE 17:
"WALK-JOG-RUN" ACTIVITIES



From the figure, NV Energy is indicating that in general the "Walk" phase has been completed and that most of the current and near-term activities of the DRP are those in the "Jog" phase. Activities in the "Jog" phase may be changed and refined going forward, while the activities in the "Run" phase should be interpreted as being more likely to change going forward. NV Energy currently expects to complete most, if not all, of the aspects of the "Jog" phase by the end of 2025. Activities in the "Run" phase will likely occur in the latter half of this decade. DRP Update-Figure 18 below gives a high-level status of the "Jog" activities.

DRP UPDATE-FIGURE 18:
"JOG" ACTIVITIES HIGH-LEVEL STATUS

Implement DERMS and enhanced ADMS (Section 9A)	• Status: IN PROGRESS • Activity: First phase complete; refer to Section 9.A
File and implement a Transportation Electrification Plan (Section 4)	• Status: IN PROGRESS • Activity: Initial plan filed; implementing; refer to Section 4
Participate in DOE Grid Services Grant project (Section 9B)	• Status: IN PROGRESS • Activity: Budget Period 1 complete; Budget Period 2 ongoing; refer to Section 9.B
Establish DER forecasting and valuation of all technologies (Section 8.A)	• Status: IN PROGRESS • Activity: RFP issued; consultant contracted; effort beginning
Establish continuous and improved GNA/NWA/LNBA processes (Sections 8.C and 8.D)	• Status: IN PROGRESS • Activity: Determining process ahead of 2024 implementation
Modernize/update the distribution interconnection rule (Rule 15) (Section 8.E)	• Status: IN PROGRESS • Activity: Benchmarking other states; determining initial edits
Investigate cost-effective NWA solutions and sourcing options (Section 8.C)	• Status: PENDING • Activity: Researching
Investigate DER microgrids to enhance customer and grid resiliency	• Status: PENDING • Activity: Researching

DRAFT NOTICE

PUBLIC UTILITIES COMMISSION OF NEVADA DRAFT NOTICE

(Applications, Tariff Filings, Complaints, and Petitions)

The Commission requires a draft notice be included will all applications, petitions and complaints. See Nevada Administrative Code 703.162. Please include one copy of this form with all the above filings.

I. A title that generally describes the relief requested (NAC 703.160(5)(a)):

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2023 Distributed Resources Plan Update as it relates to the Action Plan of their 2022-2041 Joint Integrated Resource Plan.

II. The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (NAC 703.160(5)(b)):

Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, "NV Energy" or the "Companies").

III. A brief description of the purpose of the filing or proceeding, including, without limitation, a clear and concise introductory statement that summarizes the relief requested or the type of proceeding scheduled (NAC 703.160(5)(c)):

This is a joint application for approval of the Companies' 2023 Distributed Resources Plan Update ("DRP Update") as it relates to the Action Plan of their 2022-2041 Joint Integrated Resource Plan pursuant to Sections 704.9239 and 703.535 of the Nevada Administrative Code ("NAC"). The Joint Application contains the complete analysis that Nevada Power and Sierra used for this DRP Update, which is applicable to the one year remaining in the Action Plan period, 2024.

IV. A statement indicating whether a consumer session is required to be held pursuant to Nevada Revised Statutes ("NRS") 704.069 (NAC 703.162(2)):

A consumer session is not required pursuant to NRS 704.069.

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

N/A.

JOSEPH SINOBIO

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2023 Joint Distributed Resources Plan Update

Docket No. 23-09___

Prepared Direct Testimony of

Joseph V. Sinobio

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

A. My name is Joseph V. Sinobio. I am the Integrated Grid Planning Manager for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6226 W. Sahara Ave. Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I have been continuously employed by NV Energy since September 1988. I have experience in electric utility transmission and distribution planning, and distributed energy resources ("DERs"). I have a Bachelor of Engineering degree in electrical engineering. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Sinobio-Direct-1**.

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

A. As Integrated Grid Planning Manager, my responsibilities include supporting DER planning, interconnection, impact studies, Hosting Capacity Analysis ("HCA"), Grid Needs Assessment ("GNA") analysis, Non-Wires Alternative ("NWA") analysis, and Locational Net Benefits Analysis ("LNBA") on the Companies' distribution systems. I have overall responsibility for ensuring delivery of the Companies' Distributed Resources Plan ("DRP").

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

A. Yes. I have provided written testimony and appeared before the Commission in various dockets, most recently, the application by the Companies seeking Commission approval of their 2021 Joint Integrated Resource Plan ("IRP") (Docket No. 21-06001) and their 2022 Joint DRP Update (Docket No. 22-09001). I have also participated in Commission workshops in various investigatory dockets.

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

A. My testimony is in support of certain sections of the 2023 DRP Update ("DRP Update") narrative, specifically:

- Section 1 – Executive Summary;
- Section 2 – Introduction;
- Section 3.A – Distributed Resources Plan Analyses; Distribution Planning and Integrated Grid Planning;
- Section 5 – Barriers to Deployment of Distributed Energy Resources;

- Section 7 – Publicly-Accessible DRP Web Portal;
- Section 8 – Continued Refinement of DRP Elements;
- Section 10 – Pilot and Demonstration Projects;
- Section 11 – Specific Requests for Commission Approval;
- Section 12 – View Moving Forward; and
- Technical Appendices DRP Update-1, DRP Update-2, DRP Update-3, DRP Update-4, DRP Update-5, DRP Update-6, and DRP Update-7.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring **Exhibit Sinobio-Direct-1**.

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

A. Yes. Specifically, Alex Ford is supporting Section 3.B, Adam Grant is supporting Section 4 and Subsection 6.B.1.c, Kimberly Williams is supporting Section 6.A, Patricia Rodriguez is supporting Section 6.B (with the exception of Subsection 6.B.1.c), and Michael Brown is supporting Section 9.

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

A. I oversaw the drafting of the DRP Update narrative, ensuring its adherence to all applicable regulatory and legislative requirements and its timely completion. Specifically, I oversaw the completion of the technical analyses of NV Energy's distribution systems for the DRP Update and the recommendations based on those analyses. I was responsible for:

1. Acquiring the distribution load and DER forecasts at the substation and distribution feeder levels;

2. Directing completion of the HCA studies, GNA, NWA analyses, and LNBA on the Companies' distribution systems;

3. Developing NV Energy's plan to refine several elements of the DRP;

4. Recommending any traditional wired projects, NWA solutions, and certain pilots and demonstration projects on the Companies' distribution systems; and

5. Compiling certain specific requests for Commission approval and requests for deviations from Nevada Administrative Code ("NAC") regulations.

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

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

Section 2 – *Introduction* provides details as follows:

1. *Distributed Resources Plan Alignment with NV Energy Core Principles* outlines how NV Energy's core principles align with the objectives of the DRP Update;

2. *Overview of DRP Update Contents* outlines the contents of the DRP Update;

3. *Legislative and Regulatory Requirements* lists statutory and regulatory authorities applicable to a DRP Update;

4. *Stakeholder Engagement* provides details on the robust stakeholder engagement process that NV Energy utilized in developing its DRP Update;

5. *DER Penetration on NV Energy's Grid* provides information on the level of DER penetration at the system level and on the highest penetrated distribution feeders; and

6. *Definitions and Acronyms* provides definitions of technical terms and explains any of the narrative's acronyms.

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

1. *Load and DER Forecasting* describes generally how load forecasting is performed at the distribution feeder level for the Companies, discusses the effect of DERs on distribution load forecasting, and discusses DER forecasting;

2. *Hosting Capacity Analysis* describes how the distribution substation and feeder models were prepared utilizing the Companies' Synergi Electric distribution power flow software, how the loading profile data for the Companies' distribution feeders was developed, the analytical method for the HCA, the results of the HCA, and a discussion of "real-time" hosting capacity and NV Energy's progress in that regard; and

3. *Grid Needs Assessment – 2023 Capital Plan* describes how the Companies identified existing and forecasted constraints on their distribution systems for the year 2024, the identifying information and parameters of those constraints in terms of the deficiencies involved, the identified traditional wired capital upgrade solutions for addressing those constraints, the Companies' NWA Suitability/Screening Criteria to determine which of the

identified constraints could be suitable for a potential NWA solution, the method and the NWA Screening Analysis Tool that the Companies used to perform the NWA analyses, the results of the NWA analyses, including the sizing of the DER technologies (demand response, energy efficiency, conservation voltage reduction, solar photovoltaic, and battery energy storage) used in the potential NWA portfolio, the Present Worth of Revenue Requirements ("PWRR") analyses that were performed by the Companies comparing the costs of traditional wired capital upgrade solutions against the costs and potential system-level and locational benefits of NWA solutions, and lists the traditional wired capital upgrade solutions and the NWA solutions that the Companies recommend to address the identified constraints on the distribution system.

Section 5 – *Barriers to Deployment of DER* describes the barriers that NV Energy identified that would be a deterrent to the deployment of DERs and the solutions to remove those barriers.

Section 7 – *Publicly Accessible DRP Web Portal* discusses the web portal that NV Energy developed to share the outputs from the DRP analyses with the public.

Section 8 – *Continued Refinement of DRP Elements* describes the Companies' present plans to further refine the methods and tools used in performing the various analyses required to develop the DRP over the next several years.

Section 10 – *Pilot and Demonstration Projects* describes any pilot or demonstration projects that the Companies conducted or may be proposing to

conduct in support of the analyses or tools, systems, or technologies used to support the DRP.

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

Section 12 – *View Moving Forward* provides an overview of where the efforts associated with the DRP Update sit with respect to the "walk-jog-run" philosophy employed by the Companies to evolve the DRP.

Technical Appendix DRP Update-1 contains the initial list of issues gleaned from intervenor testimony in Docket No. 21-06001 that served as the starting point for the DRP stakeholder discussion process this is currently taking place.

Technical Appendix DRP Update-2 contains substation transformer and distribution feeder past peak loads from 2018 to 2022 for both Nevada Power and Sierra.

Technical Appendix DRP Update-3 contains substation transformer and distribution feeder forecasted peak loads as of July 17, 2023, for 2023 to 2029 for both Nevada Power and Sierra.

Technical Appendix DRP Update-4 contains the DER Analytics Toolset and Potential Study Scope of Work that was included in NV Energy's competitive request for proposals solicitation for the effort issued on March 24, 2023.

Technical Appendix DRP Update-5 contains a flowchart of NV Energy's HCA monthly update process.

Technical Appendix DRP Update-6 contains NV Energy's Standard Loading Criteria.

Technical Appendix DRP Update -7 contains NV Energy's DRP web portal user guide.

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

A. Yes.

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

A. Section 11.A of the DRP Update narrative describes the Companies' requests for the Commission. Specifically, I support NV Energy's request for the Commission to find that the elements contained in the DRP Update continue to be prudent and for Commission approval of the 2023 DRP Update as compliant with NAC 704.9239 and applicable sections of 704.9237, including the following:

1. The summary describing the results of the April 27, 2023, stakeholder meeting discussed in Section 2.D.1 is in compliance with NAC 704.9237(3)(e);
2. NV Energy's load and DER forecasting methods as discussed in Section 3.A.1 is in compliance with NAC 704.9237(2)(f);
3. NV Energy's HCA methods as discussed in Section 3.A.2 are in compliance with NAC 704.9237(3)(b);
4. NV Energy's GNA methods as discussed in Section 3.A.3, including the identification of distribution constraints and projects in Section 3.A.3.a, the NWA analyses in Section 3.A.3.b, the LNBA in Section 3.A.3.c, and the traditional wired upgrade projects and NWA solutions recommendations in Section 3.A.3.d, are in compliance with NAC 704.9237(2)(a), 704.9237(3)(a), and 704.9237(3)(c);
5. The identification of barriers to the deployment of DERs discussed in Section 5 is in compliance with NAC 704.9237(2)(e);
6. The development, deployment, and updating of a publicly accessible Web Portal that provides maps and accessible electronic data discussed in Section 7 are in compliance with NAC 704.9237(5); and
7. The Technical Appendix, including Technical Appendices DRP Update-1 through DRP Update-7, is in compliance with NAC 704.9237(3)(f).

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

A. Mr. Ford is supporting the Companies' request for the Commission to approve Section 3.B as prudent and in compliance with NAC 704.9239 and applicable subsections of NAC 704.9237.

Mr. Grant is supporting the Companies' request for the Commission to approve Section 4 as in compliance with NAC 704.9237(3)(g).

Ms. Williams is supporting the Companies' request for the Commission to approve Section 6.A as in compliance with NAC 704.9237(3)(d).

Ms. Rodriguez is supporting the Companies' request for the Commission to approve Section 6.B as in compliance with NAC 704.9237(2)(c).

Mr. Brown is supporting the Companies' request for the Commission to approve Section 9 as in compliance with NAC 704.9237(2)(d).

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

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

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

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

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

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

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

NV Energy does not yet produce forecasts for all DER types as defined in NAC 704.90583 (*e.g.*, energy storage) and does not yet develop certain DER forecasts at the substation and feeder levels (*e.g.*, net energy metering solar photovoltaic ("NEM PV")). The Companies did, however, disaggregate system-level NEM PV forecasts down to the substation and feeder levels to support the analyses in this DRP Update. The results from the DRP Update analyses were not appreciably diminished due to this gap in forecast data. Additionally, as discussed in Section 3.A.1.c of the DRP Update narrative, NV Energy issued a competitive request for proposals for a DER Analytics Toolset and Potential Study effort on March 24, 2023, and recently executed a contract with a consultant on July 27, 2023, to begin this effort to close any gaps in DER forecasting and expects to use the results of that effort in support of its 2024 Joint IRP filing.

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

A. As stated in Section 3.A.2 of the DRP Update narrative, since the Companies' filing of the 2021 DRP, NV Energy performed its HCA using load flow analyses on models of the Companies' distribution systems via the Synergi Electric power flow software. NV Energy completed updating the hosting capacity of selected feeders monthly in April through December 2022 and completed HCA on more than 1,300 distribution feeders in a process spanning the first quarter of 2023. As noted in Section 3.A.2, the Companies were unable to complete their normal monthly hosting capacity update process in April through August 2023 due to an Information Technology security issue that did not allow use of the Synergi software during those months but were able to resume this process in August 2023.

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

As noted in Section 11.B of the DRP Update narrative, NV Energy is requesting a waiver of the portion of NAC 704.9237(3)(b) which requires that the DRP must include an HCA of the distribution system evaluated "*under normal conditions and planned and unplanned contingency conditions.*" NV Energy completed the HCA

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

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

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

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

A. Section 5 of the DRP Update narrative identifies potential barriers to the deployment of DERs grouped into three categories: (1) integration/interconnection of DERs with the distribution grid, (2) market limitations on the ability of DERs to deliver promised benefits, and (3) distribution system operational and infrastructure capability to handle DER value. The Companies also present some potential solutions that could address these barriers. These activities, as described in the DRP Update narrative, meet the requirements of NAC 704.9237(2)(e).

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

A. Section 7 of the DRP Update narrative discusses the publicly accessible DRP web portal and any updates to it. These activities, as described in the DRP Update narrative, meet the requirements of NAC 704.9237(5).

18. Q. ARE SECTIONS 8, 10 AND 12 OF THE DRP UPDATE NARRATIVE REQUIRED BY THE DRP UPDATE REGULATIONS?

A. No.

19. Q. WHY ARE SECTIONS 8, 10 AND 12 OF THE DRP UPDATE NARRATIVE INCLUDED AND WHAT PURPOSE DO THEY SERVE?

A. Section 8 describes the Companies' present expectations to further refine the methods and tools used in performing the various analyses required to develop the DRP. NV Energy has continued to employ a prudent "walk-jog-run" approach to developing and maturing the methods and analyses required to support the goals of the DRP. This DRP Update filing represents the fourth filing of such a plan in Nevada and it is representative of the still-emerging nature of this industry in the state and should be expected to continue to change in the coming years. In Section 8, NV Energy lays out the progression of several main elements of the DRP through the next several years.

Although some of the concepts associated with the DRP have been progressing and maturing in other states and in Nevada, NV Energy believes that it may be prudent to pilot or demonstrate certain concepts, methods, or technologies prior to a decision to employ them in the first place, how to employ them, or whether to apply or deploy them system wide. Section 10 captures any activities or recommendations in this regard.

Finally, Section 12 serves to illuminate the "walk-jog-run" approach by clarifying the activities associated with each level, thereby cultivating an understanding of where within this model the various DRP activities presently reside and how they may progress.

20. Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT SINOBIO- DIRECT-1

Statement of Qualifications
for
JOSEPH V. SINOBIO

Summary of Qualifications

Over 34 years of electric utility experience, including 29 years of leadership experience, all for NV Energy (Nevada Power Company and Sierra Pacific Power Company) based in Las Vegas, Nevada. Highly experienced in electric utility distribution planning. Experienced in management and leadership techniques, goal-setting, process analysis, capital budgeting, technical writing, and providing regulatory testimony. Expertise in distributed energy resources, interconnection, impact studies, and integrated grid planning.

Professional Experience

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

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

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

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

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

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

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

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

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

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

Manager, Distribution Planning & Analysis January 1998 – September 1999
Nevada Power Company

Directly managed a Distribution Planning team.

Manager, Distribution Planning, Standards & Analysis January 1994 – January 1998
Nevada Power Company

Managed a Distribution Planning and Distribution Standards team.

Engineer II - III, Transmission Planning July 1991 – January 1994
Nevada Power Company

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

Engineer I - II, Distribution Planning April 1989 – July 1991
Nevada Power Company

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

Training, Education, & Memberships

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

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

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

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JOSEPH SINOBIO, 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: September 1, 2023

Joseph V. Sinobio
JOSEPH SINOBIO

ALEX FORD

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2023 Joint Distributed Resources Plan Update

Docket No. 23-09_____

Prepared Direct Testimony of

Alex Ford

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

A. My name is Alex Ford. I am a Transmission Planning Engineer II in the Transmission System Planning department for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of the Companies.

2. Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering from the University of Nevada, Reno. I began my employment with the Companies as a student engineer in 2018. I have experience in transmission planning, distribution engineering, power quality analysis, and distribution protection engineering. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Ford-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS A TRANSMISSION PLANNING ENGINEER.

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

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

A Yes. I provided written testimony and appeared before the Commission in the application by the Companies seeking Commission approval of their 2021 Joint Integrated Resource Plan ("IRP") (Docket No. 21-06001), in which NV Energy's second DRP was filed.

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

A. My testimony is in support of Section 3.B of the 2023 DRP Update ("DRP Update") narrative, entitled "Distributed Resources Plan Analyses: Transmission Planning."

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring **Exhibit Ford-Direct-1**.

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

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

1. *Load Forecasting* indicates what forecasts were used in performing the transmission planning analyses in the DRP Update;
2. *Technical Analysis Methodology* describes the general methodologies used by NV Energy's Transmission Planning department when conducting NWA analyses;
3. *Grid Needs Assessment – 2023 Capital Plan* ("GNA") describes how the Companies identified existing and forecasted constraints on their transmission systems for the year 2024, the identifying information and parameters of those constraints in terms of the deficiencies involved, the identified traditional wired capital upgrade solutions for addressing those constraints, the Companies' NWA Suitability/Screening Criteria to determine which of the identified constraints could be suitable for a potential NWA solution, the method and the NWA Screening Analysis Tool that the Companies used to perform the NWA analyses, the results of the NWA analyses, including the sizing of the Distributed Energy Resource ("DER") technologies (demand response, energy efficiency, conservation voltage reduction, solar photovoltaic, and battery energy storage) used in the potential NWA portfolio, the Present Worth of Revenue Requirements ("PWRR") analyses that

were performed by the Companies comparing the costs of traditional wired capital upgrade solutions against the costs and potential system-level and locational benefits of NWA solutions, and lists the traditional wired capital upgrade solutions and the NWA solutions that the Companies recommend to address the identified constraints on the transmission system.

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

A. Yes.

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

A. Section 11 of the DRP Update narrative describes the Companies' requests for the Commission. Specifically, I support NV Energy's request for Commission approval of Section 3.B of the 2023 DRP Update narrative as compliant with Nevada Administrative Code ("NAC") 704.9239 and applicable sections of NAC 704.9237, including the following:

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

are in compliance with NAC 704.9237(2)(a), 704.9237(3)(a), and 704.9237(3)(c).

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

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

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

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

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

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

NV Energy does not yet produce forecasts for all DER types as defined in NAC 704.90583 (*e.g.*, energy storage) and does not yet develop certain DER forecasts at the substation and feeder levels (*e.g.*, net energy metering solar photovoltaic ("NEM PV")). The Companies did, however, disaggregate system-level NEM PV forecasts down to the substation and feeder levels to support the analyses in this DRP Update. The results from the DRP Update analyses were not appreciably diminished due to this gap in forecast data. Additionally, as discussed in Section 3.A.1.c of the DRP Update narrative, NV Energy issued a competitive request for proposals for a DER Analytics Toolset and Potential Study effort on March 24, 2023, and recently executed a contract with a consultant on July 27, 2023, to begin this effort to close any gaps in DER forecasting and expects to use the results of that effort in support of its 2024 Joint IRP filing.

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

A. Section 3.B.2 of the DRP Update narrative generally describes the different types of traditional wired transmission capital upgrade projects and the drivers of these projects from NV Energy's 2023 Capital Plan that underwent NWA analysis. Additionally, this section defines the general methodologies for NWA analysis applied to each type of project and describes how the driver for each project may impact the effectiveness of an NWA solution.

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

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

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

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

A. Yes.

EXHIBIT FORD- DIRECT-1

STATEMENT OF QUALIFICATIONS
ALEXANDER FORD

My name is Alexander Ford. My business address is 6100 Neil Road, Reno, Nevada. I have been employed at Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy since 2018. I am currently an Engineer II in the Transmission System Planning department for NV Energy.

I have been a transmission planning engineer since June of 2019. As a transmission planning engineer, I have performed studies for significant load additions, created transmission master plans for several geographic areas, and completed generator system impact studies. Since October of 2020, I have been the department lead on all issues related to Non-Wires Alternative analysis.

Prior to my current role, I interned in an engineering capacity in the Carson Operations department. In that position, I coordinated distribution system protection, analyzed customer power quality data, and performed distribution design for equipment replacement and additions.

I graduated from the University of Nevada, Reno, in 2019 with a Bachelor of Science Degree in Electrical Engineering.

By virtue of my employment, background, experience and education, I am a qualified witness with respect to NV Energy's analyses on its electric transmission system in support of the Distributed Resources Plan.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ALEX FORD, 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: _____September 1, 2023_____ _____
ALEX FORD

KIMBERLY WILLIAMS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2023 Joint Distributed Resources Plan Update

Docket No. 23-09___

Prepared Direct Testimony of

Kimberly Williams

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

A. My name is Kimberly Williams. I am the Director of Resource Planning and Analysis for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. My professional experience includes 23 years in the power industry, and I have a Bachelor of Science degree in Electrical Engineering. I have worked for the Companies since 2005. In addition to my work in Resource Planning and Analysis since 2020, I was Manager of Environmental Services for more than a decade and, prior to that, I was a Staff Environmental Engineer. As Manager of Environmental Services, I led a team of environmental advisors engaged in environmental permitting and compliance for power plants representing more than 6,000 MW of system capacity as well as transmission assets.

Prior to joining the Companies, I was employed as a Regulatory Compliance Coordinator for Chevron's independent power producing company for five years after holding a similar job at Berry Petroleum Company. Prior to that, I was a Facilities/Construction Engineer for ARCO Oil and Gas Company for eight years.

More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Williams-Direct-1.**

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

A. As Director of Resource Planning and Analysis, I lead a staff of economists, planners, engineers and analysts to develop the Companies' Integrated Resource Plans ("IRP") and amendments, and Energy Supply Plans and updates. In addition, working with other groups in the Companies, the Resource Planning and Analysis department develops and supports supply strategies, presents them to management for approval, and facilitates ongoing communication of the status of the supply plans.

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

A. Yes, I filed testimony with the Commission in the Companies' 2021 Joint Integrated Resource Plan ("2021 Joint IRP") -- Docket No. 21-06001, 2022 Distributed Resources Plan Update – Docket No. 22-09001, Fourth Amendment to the 2021 Joint IRP – Docket No. 22-11032, and Fifth Amendment to the 2021 Joint IRP – Docket No. 23-08015.

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

A. My testimony is in support of Section 6.A of the 2023 Distributed Resources Plan Update ("DRP Update") narrative, entitled "DRP Coordination with Other Components of the IRP and Commission-Approved Programs: Coordination with Other Components of the IRP."

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring **Exhibit Williams-Direct-1**.

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

A. **Section 6.A** – *DRP Coordination with Other Components of the IRP and Commission-Approved Programs: Coordination with Other Components of the IRP* describes how the Companies have incorporated distributed energy resources ("DERs") planning within the integrated resource planning process.

8. Q. HOW HAVE THE COMPANIES INCORPORATED DER PLANNING INTO THE INTEGRATED RESOURCE PLANNING PROCESS?

A. The integrated resource planning process continues to evolve as technologies and public policies emerge. In 2017, the Nevada State Legislature passed Senate Bill 146 ("SB146") requiring the Companies to file a DRP and incorporate DER planning into the IRP planning process. NV Energy filed its first DRP as an amendment to the 2018 IRP. The Companies' 2021 IRP filing marked the first time the DRP was incorporated into a full IRP filing.

The IRP presents a joint system-level loads and resources needed to meet native load customer requirements over the long term. The DRP addresses distribution-level resources and sets forth the plans and strategies to meet near-term locational system and customer needs. Integrating DERs will impact the need for the Companies to build new capital wired distribution upgrades, will impact the net loading on specific feeders within the system, and can delay the need for such distribution facilities.

9. Q. HOW HAVE DERs IMPACTED THE NEED FOR SUPPLY-SIDE RESOURCES IN THE INTEGRATED RESOURCE PLANNING PROCESS?

A. As the amount of privately-owned generation and energy storage technologies continue to increase, it will increasingly impact system-level load forecasts and supply-side options. As described in the load forecast section of the Third Amendment to the 2021 Joint IRP ("Amendment"), NV Energy adjusts the system-level forecast for the penetration of privately-owned generation, energy storage and electric vehicle capacity. The evaluation of DER technologies as alternatives to investment by the utility in traditional wired capital solutions (*i.e.*, the Non-Wires Alternative process) has not yet impacted the need for supply-side and transmission assets in the integrated resource planning process.

NV Energy will continue to monitor the deployment of DERs through both existing Commission-approved programs and the DRP process and will assess the impact of these resources in future IRPs. As DERs continue to expand on the NV Energy system, a stronger relationship between the DRP and other components of the IRP is expected to develop.

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

A. Yes.

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

A. Section 11 of the DRP Update narrative describes the Companies' requests for the Commission. I support NV Energy's request for Commission approval of Section 6.A of the 2023 DRP Update narrative as in compliance with Nevada Administrative Code ("NAC") 704.9237(3)(d).

12. Q. PLEASE DISCUSS WHY THE COMMISSION SHOULD FIND NV ENERGY'S SUMMARY EXPLAINING HOW DERs HAVE AFFECTED THE NEED FOR SUPPLY-SIDE RESOURCES IN THE RESOURCE PLANNING PROCESS AS DISCUSSED IN SECTION 6.A OF THE DRP UPDATE AS IN COMPLIANCE WITH NAC 704.9237(3)(d).

A. Section 6.A of the DRP Update fully describes how DERs have affected the need for supply-side resources. My testimony, and specifically Q&As 8 and 9 above, also describes the relationship between DERs and the resource planning process.

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

A. Yes.

EXHIBIT WILLIAMS- DIRECT-1

STATEMENT OF QUALIFICATIONS
KIMBERLY L. WILLIAMS
NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANY d/b/a NV Energy

6226 W. Sahara Ave.
Las Vegas Nevada 89146
(702) 402-2184

EDUCATION

THE UNIVERSITY OF TEXAS AT AUSTIN – Austin, Texas
Bachelor of Science in Electrical Engineering

PROFESSIONAL EXPERIENCE

NV ENERGY – Las Vegas, Nevada (2005 to Present)

Director – Resource Planning and Analysis

- Oversight of the Resource Planning and Analysis team
- Development of the Companies' integrated resource plans and amendments, energy supply plans and updates, and gas information reports
- Oversite of production cost modeling and economic analysis related to intermediate and long-term planning activities of the Companies

Manager – Resource Planning

- Leads the preparation, filing, and discovery process of the Companies' Resource Planning filings
- Facilitates internal and external studies and evaluations in support of resource planning, business plans, and regulatory filings
- Coordinates with production cost modelers on assessment of needs and plan development for integrated resource plans

Manager – Environmental Services

- Led a team engaged in permitting and compliance for generation and transmission assets and ancillary facilities
- Led teams to identify, resolve, and report compliance concerns while building relationships with regulatory agencies
- Monitored regulatory developments, created compliance strategies, and provided guidance to management
- Performed due diligence on power plant acquisitions
- Developed environmental goals and methodologies for tracking sustainability initiatives

Staff Environmental Engineer

- Performed environmental permitting for power plants
- Supported construction and commissioning of combined cycle and simple cycle power plants
- Performed due diligence on power plant acquisitions

CHEVRON GLOBAL POWER GENERATION – Bakersfield, California (2000 to 2005)

Regulatory Compliance Coordinator

- Organized, directed, and coordinated environmental compliance and permitting activities for cogeneration facilities and a combined cycle power plant
- Managed environmental compliance during new simple cycle plant commissioning and conversion from simple cycle to combined cycle
- Tracked status of all permit requirements and reported to California Energy Commission monthly during construction of combined cycle plant

BERRY PETROLEUM COMPANY – Taft, California (1999 to 2000)

Environmental Advisor

- Ensured environmental compliance for all company oilfields and cogeneration plants in three California air districts
- Performed economic evaluation of environmental projects, proposed innovative solutions, and obtained permits
- Initiated and developed internal environmental and safety audits of company assets

ARCO OIL AND GAS COMPANY – Midland, Texas and Bakersfield, California (1990 to 1999)

Facilities/Construction Engineer

- Provided facility engineering and project management for several oil fields
- Supervised contract engineering and construction personnel

Engineering Development Program

- Provided diverse engineering support across departments throughout company

Summer Intern - Engineering

INDUSTRY ADVOCACY

COMBUSTION TURBINE OPERATIONS TECHNICAL FORUM ("CTOTF")

- 2022: Growth and Development, Executive Vice Chair
- 2021-2022: Leadership Development Roundtable, Chair
- 2015-2021: Environmental Roundtable, Chair
- 2012-2014: Regulatory and Compliance Roundtable, Vice Chair

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, KIMBERLY WILLIAMS, 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: September 1, 2023

KIMBERLY WILLIAMS

PATRICIA RODRIGUEZ

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2023 Joint Distributed Resources Plan Update

Docket No. 23-09___

Prepared Direct Testimony of

Patricia Rodriguez

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

A. My name is Patricia Rodriguez. My current position is Director, Energy Services Optimization, for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of NV Energy.

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

A. My professional experience includes more than 18 years in the utility industry. I have a Bachelor of Science in Electrical Engineering and have been employed by NV Energy since May 2005. Prior to my current position, I held positions in Distribution Planning, Resource Planning, Demand Side Management, and Project Controls. I provide the details of my background and experience in **Exhibit Rodriguez-Direct-1.**

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, ENERGY SERVICES OPTIMIZATION.

A. As the Director of Energy Services Optimization, I provide direction and leadership for the optimization of customer programs and distributed energy resource technologies for the benefit of the grid and NV Energy customers through the Distributed Resource Plan. I am also responsible for the regulatory compliance, financial planning and reporting, stakeholder management, technical analysis, systems implementation, and customer outreach for Integrated Energy Services.

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

A. Yes, I have testified in several proceedings before the Commission. Most recently, I provided testimony before this Commission in Docket Nos. 18-03002, 18-03003, 18-03004, 18-06003, 19-07004, 19-07005, 20-07004, 21-02004, 21-06001, 22-07003, 22-09006, and 23-06044.

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

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

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

A. I am supporting Section 6.B - *DRP Coordination with Other Components of the IRP and Commission-Approved Programs: Coordination with Existing Commission-Approved DER Programs*, with the exception of Subsection 6.B.1.c which is supported by Mr. Adam Grant.

7. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF SECTION 6.B OF THE DRP NARRATIVE THAT YOU ARE SUPPORTING IN THIS FILING.

A. Section 6.B - *Coordination with Existing Commission-Approved DER Programs* provides the Companies' review of the existing legislatively-mandated programs addressing the deployment of Distributed Energy Resources ("DERs"), including energy education, DSM, clean energy incentive programs, the Economic Recovery Transportation Electrification Plan, and supplementary tariffs.

8. Q. WHICH SPECIFIC REQUESTS FOR APPROVAL ARE YOU SUPPORTING IN THIS TESTIMONY?

A. Section 11 of the DRP narrative describes the Companies' specific requests for approval, which include compliance with the appropriate sections of Nevada Administrative Code ("NAC") determinations. I support the request for Commission finding that NV Energy identified existing programs and tariffs approved by the Commission that address the deployment of DERs and the methods of effectively coordinating these programs to maximize the locational benefits and minimize the incremental costs of DERs as discussed in Section 6.B of the DRP narrative in compliance with NAC 704.9237(2)(c).

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9. Q. PLEASE DISCUSS WHY THE COMMISSION SHOULD FIND NV ENERGY'S IDENTIFICATION OF THE EXISTING PROGRAMS, TARIFFS AND INCENTIVES, AND METHODS OF COORDINATING THE DEPLOYMENT OF DERS WITH SUCH PROGRAMS IN SECTION 6.B OF THE DRP NARRATIVE AS PRUDENT AND IN COMPLIANCE WITH NAC 704.9237(2)(c).

A. NV Energy lists and describes all the appropriate existing Commission-approved programs, tariffs, and incentives that address the deployment of DERs in Section 6.B.1 of the DRP narrative. These programs, tariffs, and incentives relate to energy efficiency, DR, solar PV distributed generation systems, electric vehicles, and energy storage, all of which are technologies defined in NAC 704.90583 as distributed resources. Therefore, NV Energy's identification of the existing Commission-approved programs, tariffs, and incentives in Section 6.B.1 of the DRP narrative meets the requirements of NAC 704.9237(2)(c).

NV Energy describes how the identified Commission-approved programs cost-effectively coordinate with each other and with the unique activities and analyses in the DRP (*e.g.*, the Hosting Capacity Analysis and Non-Wires Alternatives analyses) to maximize the locational benefits and minimize the incremental costs of distributed resources in Section 6.B.2 of the DRP narrative. The information provided in that section also meets the requirements of NAC 704.9237(2)(c).

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10. Q. NOW THAT THE CLEAN ENERGY PROGRAMS HAVE ENDED, WHAT OTHER PROGRAMS DOES NV ENERGY HAVE AVAILABLE IN SUPPORT OF DER DEPLOYMENT?

A. Clean Energy programs provided customer incentives for electric vehicle infrastructure, renewable generation systems, and battery storage. With the Legislative mandate and Commission approval, NV Energy is launching new electric vehicle programs in the Economic Recovery Transportation Electrification Plan and the Transportation Electrification Plan to support the adoption of electric vehicles and the associated infrastructure. NV Energy also continues to support the interconnection of DERs through non-incentive solar and storage applications. NV Energy can recruit these customers into Demand Response programs and future peak shifting programs to create grid flexibility.

11. Q. PLEASE EXPLAIN THE ENERGY STORAGE SYSTEM DR TRIAL PROGRAM MEASURE.

A. NV Energy is recruiting customers to enroll their energy storage system ("ESS") into the Residential DR program. DR dispatch signals provide the battery control system with a start time, duration, and control commands with payload for discharge. The program incentivizes customers to enroll their DR-enabled ESS and participate in community energy events. Incentives are based on a $25/kilowatt ("kW") nameplate rating of the customer ESS and are paid by bill credits at the end of each year of participation. The enrollment customer goal is 73 ESS premises in 2023. Depending on the number of premises that are enrolled, NV Energy anticipates that each battery will provide an average demand reduction of 3.15 kW during events. NV Energy recognizes the need to diversify customer assets participating in DR programs to provide more flexible levels of DR capacity and capability.

12. Q. PLEASE EXPLAIN THE EV DETECTION AND MANAGED CHARGING TRIAL?

A. In order to learn about customer charging habits and preferences prior to requesting funding to support a formal program, the Companies have engaged its vendor to do a no-cost trial. After detecting electric vehicles using smart meter disaggregation, customers who have a significant portion of EV load on-peak are recruited for a managed charging trial. Customers who charge more than 25 percent of the time on peak will be sent an invitation via email to join a managed charging trial. The goal for participation is 100 customers. The connection to the vehicle via telematics enables data to be collected straight from the vehicle and, in some cases, allows the vehicle charging to be automated to align to time-of-use rates and flex demand events.

13. Q. WAS NV ENERGY SUCCESSFUL IN ITS GEO-TARGETED DR DEMONSTRATIONS?

A. Yes, as proven by the DR program demonstrations on the four distribution facilities: Village, Northwest (in Nevada Power's territory), Leavitt, and Bicentennial Substation. NV Energy was able to successfully utilize geo-targeted efforts when needed by distribution and system-level operations and has shown that this method can be relied upon to support meeting customer load in high peak events. These events support maintaining service reliability in specific geographic areas and avoids potential facility overloading. NV Energy will continue to use this method on areas that are determined to be hot spots.[1]

[1] NV Energy defines a "hot spot" as a distribution facility that is forecasted to have loading, phase balancing and/or voltage outside normal parameters under normal operating conditions, where a solution may or may not be completed in time to prevent the undesirable condition.

14. Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes it does.

EXHIBIT RODRIGUEZ- DIRECT-1

STATEMENT OF QUALIFICATIONS

PATRICIA RODRIGUEZ

NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANIES d/b/a NV Energy
6226 W. Sahara Ave.
Las Vegas Nevada 89146
(702) 402-2434

Education

Bachelor of Science in Electrical Engineering, University of Nevada Las Vegas 2005.

Professional Experience

2019 through present — **Director, Energy Services Optimization**
NV Energy

Responsibilities include oversight leadership of the Demand Side Management team and as of September 2020 also lead the Clean Energy team. Additional responsibilities include development and implementation, analysis and cost recovery of cost-effective statewide demand side management, Clean Energy and Transportation Electrification programs which provide exceptional service to customers.

2018 through 2019 — **Manager, Distribution Planning**
NV Energy

Responsibilities include leading and directing efforts of the engineering staff comprising Distribution Planning. Additional responsibilities include ensuing that cost effective plans specifying the scope and timing of distribution infrastructure additions and improvements necessary to maintain service reliability and accommodate future load additions are developed and periodically updated in an efficient, skillful, coordinated and timely manner.

2015 through 2018 — **Manager, Gas Transportation Planning**
NV Energy

Responsibilities include planning and analysis of gas transportation needs to ensure sufficient supply to the generation fleet and natural gas customers. Additional responsibilities include development and implementation of work plans to support corporate contract negotiations, planning, budgeting, controls, portfolio optimization, cost reduction and risk management.

2014 through 2015 — **Senior Engineer, Distribution Planning**
NV Energy

Responsibilities included performing contingency analysis, distribution load flow analysis and providing service requirements for distribution load additions for area of responsibility (NVE Northeast Region). Additional responsibilities included working on different studies for renewable Rule 15 projects.

2012 through 2014 **Staff Consultant, DSM Planning**
NV Energy

Responsibilities included the planning, development and evaluation of Demand Side Management (DSM) programs including program selection and development, financial analysis, preparation of the DSM portion of the resource plan, measurement and verification of program results, analysis of results of programs and associated reporting.

2011 through 2012 **Senior Engineer, Distribution Planning**
NV Energy

Responsibilities included performing contingency analysis, distribution load flow analysis and providing service requirements for distribution load additions for area of responsibility (NVE Northwest Region). Additional responsibilities included working on different studies for mine additions served at the distribution level.

2008 through 2011 **Engineer, Distribution Planning**
NV Energy

Responsibilities included supporting the analysis and development of hot spot solutions, completing the Long Range Capacity Plan and providing service requirements for distribution load additions for area of responsibility. Additional responsibilities included the creation of the load forecast for substation transformers and feeders, distribution load flow analysis and updating the capital budget planning initiation documents based on the new forecast.

2007 through 2008 **Senior Consultant, Project Controls**
NV Energy

Responsibilities included monitoring and updating fully integrated design and construction project schedules, providing resource histograms, analyzing, reviewing and forecasting performance for various capital projects. Additional responsibilities included providing Primavera training to project managers, functional groups and project controls staff.

2005 through 2007 **Associate Engineer, Project Controls**
Nevada Power Company

Responsibilities and accomplishments included the development and maintenance of design and construction project schedules and the integration of them into the master project management schedule. Additional responsibilities included creating monthly reports and facilitating meetings with functional group leaders and project managers to review project progress.

2005 **Student Intern, Project Controls**
Nevada Power Company

Responsibilities and accomplishments included construction schedule updates, research and data entry for various systems.

Memberships

Board member of Childrens Discovery Museum and executive SWEEP board and Vice Chair.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, PATRICIA RODRIGUEZ, 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: September 1, 2023

PATRICIA RODRIGUEZ

ADAM GRANT

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2023 Joint Distributed Resources Plan Update

Docket No. 23-09____

Prepared Direct Testimony of

Adam Grant

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

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

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

A. My professional experience includes 16 years in the utility industry. I have held a variety of positions with NV Energy since I joined Nevada Power as a Communications Specialist in 2007. The details of my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Grant-Direct-1.**

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

A. As Director of Electrification and Energy Services, my responsibilities include oversight of the overall delivery of the Companies' residential and commercial demand side management ("DSM") programs, transportation electrification programs, clean energy programs, and energy services customer engagement.

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

A. Yes, I have testified in numerous proceedings before the Commission, most recently in Docket Nos. 22-03001/3002 (deferred energy accounting adjustment), 22-07004 (DSM Update), and 23-06044 (DSM Update).

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

A. My testimony supports Section 4 and Subsection 6.B.1.c of the 2023 Distributed Resources Plan Update ("DRP Update") narrative, entitled "Transportation Electrification Plan Update" and "Economic Recovery Transportation Electrification Plan," respectively.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring **Exhibit Grant-Direct-1**, my Statement of Qualifications.

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7. Q. PLEASE GENERALLY DESCRIBE THE CONTENT OF SECTION 4 AND SUBSECTION 6.B.1.C OF THE DRP NARRATIVE THAT YOU ARE SUPPORTING IN THIS FILING.

A. **Section 4** – *Transportation Electrification Plan Update* provides the Companies' summary of its recently-approved Transportation Electrification Plan ("TEP") and current planned activities to implement its TEP in 2024.

Subsection 6.B.1.c – *Economic Recovery Transportation Electrification Plan* ("ERTEP") describes the Companies' ERTEP programs.

8. Q. WHICH SPECIFIC REQUESTS FOR APPROVAL ARE YOU SUPPORTING IN THIS TESTIMONY?

A. Section 11 of the DRP Update narrative describes the Companies' specific requests for approval, which include prudency and compliance with the appropriate sections of Nevada Administrative Code ("NAC") determinations. I support NV Energy's request for Commission approval of the updates to the Transportation Electrification Plan in Section 4 of the 2023 DRP Update narrative as in compliance with NAC 704.9239 and 704.9237(3)(g)(1), as adopted through LCB File No. R005-22 regulation.

9. Q. PLEASE DISCUSS WHY THE COMMISSION SHOULD FIND NV ENERGY'S UPDATE OF ITS TEP IN SECTION 4 OF THE DRP UPDATE AS IN COMPLIANCE WITH NAC 704.9237(3)(g)(1).

A. Section 4 of the DRP Update narrative provides updates for the programs that were approved by the Commission in Docket No. 22-09006. Currently, NV Energy has spent $2,254,926 on program management work to begin implementing the programs. The bulk of these costs are attributed to work on developing the plan

prior to Commision approval. The update provides an overview of Interstate Corridor Charging Depot Program, Electric School Bus Vehicle-to-Grid ("V2G") Trial, and the Inflation Reduction Act ("IRA") Innovation Demonstration Program. Plans for continuing the implementation of the programs during 2024 are also contained in Section 4. The information in Section 4 of the DRP Update narrative meets the requirements of NAC 704.9237(3)(g)(1).

10. Q. WHAT PROGRESS HAS BEEN MADE FOR THE THREE TEP PROGRAMS IN 2023 AND WHAT PROGRESS DO YOU ANTICIPATE IN 2024?

A. The TEP, which builds on currently implemented ERTEP programs, is being prepared for open enrollment. Due to the accelerated timeline of ERTEP as well as ERTEP's prioritization of job creation and workforce development, NV Energy is prioritizing enrolling customers into the ERTEP programs. Once program implementation is complete, eligible sites will be able to submit interest forms and be evaluated for program participation.

NV Energy is working to align the Interstate Corridor Charging Depot program with the Nevada Department of Transportation's Phase II plans to strategically deploy additional National Electric Vehicle Infrastructure compliant stations along the Alternative Fuels Corridor. NV Energy is working collaboratively with the Nevada Department of Transportation to identify site locations and soliciting site hosts.

Through the IRA Innovation Demonstration program, NV Energy reserves funding for integrating renewable generation and energy storage systems to learn how to coordinate these technologies with charging stations. The program is specifically

for customer sites that have shade canopys and, at this time, no customer is eligible for the program.

In furtherance of expanding the reach of the Electric School Bus V2G Trial Program, the Companies have partnered with Nevada Clean Energy Fund to support rural public school districts in their school bus fleet electrification plans.

In 2024, NV Energy will continue progress towards fully implementing the TEP programs as they were approved in Docket No. 22-09006.

11. Q. DOES NV ENERGY PROPOSE ANY NEW CHANGES TO THE TEP PROGRAMS FOR THE 2024 PROGRAM YEAR?

A. No. NV Energy will continue to implement the programs as approved by the Commission in Docket No. 22-09006.

12. Q. DOES NV ENERGY HAVE INFORMATION PERTAINING TO PROGRAM PARTICIPATION, CHARGING NETWORK PERFORMANCE, PERCENTAGE OF SPEND BENEFITING UNDERSERVED COMMUNITIES, CUSTOMER OUTREACH, AND EDUCATION AS NV ENERGY PROPOSED IN SECTION 10.3 OF THE TEP IN DOCKET NO. 22-09006?

A. As of the filing of the DRP Update, NV Energy does not have any data to report. This information will be provided in future TEP filings when data becomes available.

13. Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes it does.

EXHIBIT GRANT- DIRECT-1

STATEMENT OF QUALIFICATIONS

ADAM GRANT

NEVADA POWER COMPANY d/b/a NV Energy
SIERRA PACIFIC POWER COMPANIES d/b/a NV Energy
6226 W. Sahara Ave.
Las Vegas Nevada 89146
(702) 402-2183

Professional Experience

2022 to Date — **Director, Electrification and Energy Services**
NV Energy

As Director, Electrification and Energy Services, provides direction for the development, design and delivery of electrification and energy services customer programs which include energy efficiency and demand side management programs, renewable energy programs, economic recovery transportation electrification programs, and transportation electrification programs.

2015-2022 — **Manager, DSM Program Delivery**
NV Energy

Managed delivery of all Sierra Pacific Power and Nevada Power Companies' electric and gas DSM programs. Manage implementation of integrated programs with duties that include oversight of implementation contractors and vendor contract negotiations, overall portfolio and program budget management, and day-to-day program operations. A member of the DSM planning team responsible for designing future DSM programs.

2009-2015 — **Senior Project Manager, DSM**
NV Energy

Managed energy efficiency programs including Commercial Program, Residential Lighting Program, and Second Refrigerator Recycling Program for Sierra Pacific Power and Nevada Power Companies. Prepared all necessary inputs for the Sierra Pacific and Nevda Power regulatory filings including program data sheets for Integrated Resource Plans, DSM Annual Electric and Gas Report Updates.

2007-2009 — **Media Specialist, Corporate Communications**
NV Energy

Media Strategist for both Sierra Pacific Power and Nevada Power Copmpanies. Assisted in creating branding and marketing strategy and performed tasks and interviews as the Companies' spokesman.

Education

Bachelor of Arts in Law & Society, University of California at Santa Barbara, 1992

Boards and Honors

Certified Energy Manager, 2014

Association of Energy Service Professionals, member

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, ADAM GRANT, 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: September 1, 2023

ADAM GRANT

MICHAEL BROWN

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

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

2023 Joint Distributed Resources Plan Update

Docket No. 23-09____

Prepared Direct Testimony of

Michael O. Brown

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

A. My name is Michael O. Brown. My job title is Energy Services Director for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" and, together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6226 W. Sahara Ave. Las Vegas, Nevada. I am filing testimony on behalf of the Companies.

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

A. I have more than 21 years of experience in energy efficiency, renewable energy, demand response ("DR"), distributed energy resources, dynamic pricing, and advanced meter and smart grid infrastructure in a variety of roles. I have been continuously employed by NV Energy since September 2005, working in the Demand Side Management ("DSM") and Renewable Energy and Origination departments focused on building out integrated energy efficiency and DR programs and related infrastructure and services. I have supported major projects such as the statewide advanced meter infrastructure deployment and the Nevada Dynamic

Pricing Trial. I have a Bachelor of Science degree in chemistry and international relations as well as a Master of Business Administration. More details regarding my professional background and experience are set forth in my Statement of Qualifications, included as **Exhibit Brown-Direct-1**.

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

A. My responsibilities include supporting DSM and distributed energy resource ("DER") planning, DR and DER program services support, DR and DER technology research and development, and development and management of energy efficiency, DR and DER-related pilot projects, demonstrations, and trials.

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

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

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

A. My testimony is in support of Section 9 of the 2023 DRP Update ("DRP Update") narrative, entitled "Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Energy Resources."

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

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

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

A. **Section 9** – *Incremental Investment in Tools, Systems, or Technologies to Integrate Distributed Energy Resources* provides updates on two projects that were approved by the Commission in the 2021 DRP filing in Docket No. 21-06001. The first project update focuses on the status of the capital project to build a Distributed Energy Resource Management System ("DERMS"). The second update focuses on NV Energy's participation in a United States Department of Energy ("DOE") funded cooperative agreement referred to as the DOE Grid Services Set ("GSS") Grant project. The DOE GSS Grant is a collaborative project. The project team includes the University of Nevada, Reno ("UNR"), University of Nevada, Las Vegas ("UNLV"), and a private software development company Evolution Networks (collectively, including NV Energy, the "Project Team"). The DOE is funding research, software development, and field demonstration of novel services from aggregated DERs. In addition to the cost share required under the cooperative agreement, NV Energy is funding a capital project to install a 1-megawatt/4-

megawatt-hour battery energy storage system ("BESS") at its Beltway Substation in Las Vegas to support testing of the software and services developed under the cooperative agreement.

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

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

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

The Parties continue to be engaged in solution design workshops to flush out the details of how future releases will meet each of the remaining functional requirements. The budget estimates currently remain the same as those filed in Docket No. 21-06001.

A second release—originally targeted for first quarter of 2024 to fully replace NV Energy's existing Demand Response Management System—has been pushed further into 2024 due to the complexity of the design process. This release should

be ready in time to support the 2025 load control season. Future releases will integrate additional DER types and programs. The operational control of those DERs will be tightly integrated with an upgraded Advanced Distribution Management System from Oracle called Oracle Network Management System ("NMS"). Theses releases are currently scheduled to start rolling out in 2026.

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

A. The DOE GSS Grant project is divided into three major phases referred to as Budget Periods. Each budget period has specific deliverables that must be completed and accepted by DOE before authorization to proceed into the next phase. The Project Team completed the research phase of the project—Budget Period 1—on January 31, 2022. DOE approved the Project Team's continuation application, and the team is currently working on the development phase of the project in Budget Period 2. This phase includes software development and additional preparations for the Budget Period 3 demonstration phase. Budget Period 2 has been extended through the end of 2023 as the Project Team continues to develop and test new grid services and a distributed communications and control architecture.

The Beltway Substation BESS was placed in service on April 29, 2023, after successful installation and commissioning. The BESS is currently operating on pre-configured schedules and is available to support grid services testing.

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

A. Yes.

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

A. Section 11 of the DRP Update narrative describes the Companies' requests for the Commission. I support NV Energy's request for Commission approval of Section 9 of the 2023 DRP Update narrative as in compliance with Nevada Administrative Code ("NAC") 704.9237(2)(d).

12. Q. PLEASE DISCUSS WHY THE COMMISSION SHOULD FIND NV ENERGY'S IDENTIFICATION OF ANY INCREMENTAL UTILITY INVESTMENT OR EXPENDITURE NECESSARY TO INTEGRATE COST-EFFECTIVE DERs AS DISCUSSED IN SECTION 9 OF THE DRP UPDATE AS IN COMPLIANCE WITH NAC 704.9237(2)(d).

A. Section 9 of the DRP Update fully describes the status of NV Energy's efforts to cost-effectively integrate, control, and develop grid services for DERs through the DERMS and DOE GSS Grant projects, which require incremental investment on the part of the Companies. My testimony, and specifically Q&As 7, 8, and 9, also describe these efforts.

13. Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT BROWN- DIRECT-1

Statement of Qualifications
for
MICHAEL O. BROWN
MANAGER, DSM SERVICES
NV ENERGY

6226 West Sahara Avenue
Las Vegas, Nevada 89146
(702) 402-5421
Michael.Brown@NVEnergy.com

Summary of Qualifications

Michael has more than 20 years of direct experience in the energy sector with a focus on demand response, energy efficiency, and renewable energy in both deregulated and regulated electricity markets. He has held a variety of positions at consulting and energy service firms, including leadership roles in energy systems analysis; energy efficiency and renewable energy project development and project management; key account management for energy and commodity (gas and electricity) services; product development; and strategy development. Since 2005, Michael has worked at NV Energy. Michael's efforts at NV Energy have included the design and implementation of: one of the largest two-way communicating programmable thermostat programs in the country; an award-winning Home Energy Management program that integrates energy efficiency and demand response; a portfolio of commercial demand response programs utilizing open standard automated communications; and an advanced Demand Response Management System that allows demand side resources to actively participate in utility energy resource portfolio optimization and risk management processes.

Relevant Employment History

NV Energy, Manager (December 2010 – Present)

- Performs strategy, technology, and product development for distributed energy resource services.
- Manages a team responsible for providing core services in support of the delivery of integrated demand side management programs. Managed services include customer recruitment, customer operations, field services, analytics, engineering, and operations.
- Manages a team responsible for delivering a portfolio of residential, commercial, and agricultural demand response programs, and distributed energy resource integration and optimization.
- Responsibilities include program design and implementation, contract structuring and execution, business process improvement, stakeholder management, analysis of new products and services, business case development, and integration of demand side resources with smart grid infrastructure.

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

- Key program management responsibilities included residential and small commercial

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

Nevada Power Company, Strategist (September 2005 – May 2006)
- Worked in the DSM planning department to design and develop energy efficiency programs.
- Developed zero energy homes and energy information pilot programs.

Energis Pax, Consultant (January 2004 – September 2005)
- Continued distributed generation strategy development work from business school project for BOC (British Oxygen).
- Evaluated and pursued Clean Development Mechanism opportunities in India.

Luthin Consulting, Contractor (June 2002 – September 2002)
- Short-term contract for energy and commodity management services for health care facilities in New York.

Enron Energy Services (EES), Account Manager (June 2000 to December 2001)
- Managed the operations of energy outsource and large commodity contracts valued in excess of $300 million.
- Identified additional energy efficiency and demand response opportunities for clients.
- Worked with product structuring group to develop demand response products. Launched a demand response product for customers in New York and Massachusetts and provided leadership and training to fellow account managers in evolving demand response markets in the NYISO and New England ISO.

Enron Energy Services (EES), Project Developer (March 1999 to June 2000)
- Identified and developed energy efficiency projects in industrial and commercial buildings.
- Evaluated energy efficiency technologies and the impact of deregulation on project economics.

ICRC Energy Inc., Project Manager, Energy Services (January 1998 to March 1999)
- Managed a contract with the National Renewable Energy Laboratory (NREL) and the Federal Energy Management Program (FEMP) to provide technical assistance to Federal facilities.
- Performed energy efficiency and renewable energy feasibility studies and energy systems design aid.

McNeil Technologies, Inc. and Good Consulting Co., Energy Analyst
(June 1995 to January 1998)

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

Education

- **The College of William and Mary**
  Bachelor of Science, Double Major, Chemistry and International Relations, May 1994

- **The Cranfield School of Management**
  Master of Business Administration, September 2003

Memberships

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

Utility Load Management Exchange (ULME)

Association of Energy Service Professionals (AESP)

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

Industry Recognition

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

2014 PLMA Award for Outstanding Commercial Demand Response Program Design

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

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

AFFIRMATION

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

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

Date: September 1, 2023

MICHAEL BROWN

TECHNICAL APPENDIX

DRP UPDATE-1

DOCKET NO. 21-06001: DRP STAKEHOLDER PROCESS INITIAL ISSUES LIST

No.	Docket No.	Reference[1]	Issue	From Stakeholder
1	21-06001	At 132, para. 332	NV Energy should perform a PWRR analysis for all NWAs.	BCP
2	21-06001	At 120, para. 302	NV Energy should develop lead time estimates for the implementation of NWAs.	NCARE
3	21-06001	At 120, para. 302	NV Energy should conduct in-depth analysis prior to NWA lead times if initial NWA analysis demonstrates potential cost-effectiveness and if following year analysis would not provide enough lead time for NWA implementation.	NCARE
4	21-06001	At 121, para. 302	NV Energy should conduct in-depth analysis of the Lazy 5 Substation project.	NCARE
5	22-09001	Attachment 1, at 3, para. 2	NV Energy will collaborate with stakeholders to determine the cadence and agenda for meetings that will address intervener concerns in Docket Nos. 22-09001 and 21-06001 related to refining the Locational Net Benefits Analysis ("LNBA") analysis in the DRP moving forward.	WRA
6	21-06001	At 122, para. 308; and 123, para.309	Lack of, and consideration/quantification of additional benefits of DERs (LNBA) within the NWA analysis. The LNBA analysis does not appear to consider the avoided energy and production capacity benefits of EE, conservation voltage reduction ("CVR"), or DR, and the spreadsheets that NV Energy used to calculate the LNBA for NW A portfolios appear to omit any energy or capacity values from those resources.	Vote Solar
7	21-06001	At 123, para. 309	Energy arbitrage value utilizing the difference between peak and off-peak prices assuming a 25 MW four-hour battery ignores the additional benefits provided by a BESS 's ability to dispatch over shorter periods than an hour.	Vote Solar
8	21-06001	At 123, para. 309	NV Energy should quantify the energy arbitrage benefits of BESS on a sub-hourly and not just an hourly basis.	Vote Solar
9	21-06001	At 124, para. 310	Outdated hourly production cost modelling tool (PROMOD) does not identify additional benefits available from BESS for durations less than an hour.	Vote Solar
10	21-06001	At 124, para. 310	PROMOD does not have a function for BESS simulations.	Vote Solar
11	21-06001	At 124, para. 310	PROMOD models BESS as pumped hydro storage which misses benefits that battery storage provides when responding to system need.	Vote Solar
12	21-06001	At 124, para. 310	PROMOD inaccurately models dispatch of BESS.	Vote Solar
13	21-06001	At 124, para. 310	PROMOD does not take into account battery storage's quicker response to system needs.	Vote Solar
14	21-06001	At 124, para. 310	NV Energy's assumption of a low number of cycles for battery storage (25 cycles per year) instead of the standard practice of 10,000 cycles or a 10-year warranty.	Vote Solar
15	21-06001	At 124, para. 311	NV Energy use of utility-scale rather than distributed-scale solar cost estimates.	Vote Solar
16	21-06001	At 124, para. 311	NV Energy's assumption of constant solar capacity credit.	Vote Solar
17	21-06001	At 125, para. 311	NV Energy's lack of modeling of distributed solar ELCC.	Vote Solar
18	21-06001	At 125, para. 312	NV Energy's NWA analysis fails to properly value demand response resources and its demand response modeling includes no demand response in the NWA evaluation for five feeders despite NV Energy having a total of 11.2 MW of demand response programs.	Vote Solar
19	21-06001	At 125, para. 313	NV Enery should consider coincidence factors for each of the alternatives considered in the NWA.	Vote Solar
20	21-06001	At 126, para. 314	Use of energy storage as a demand response solution. As an NWA, energy storage is limited in NV Energy's Joint Amended Application.	Vote Solar

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DOCKET NO. 21-06001: DRP STAKEHOLDER PROCESS INITIAL ISSUES LIST

No.	Docket No.	Reference[1]	Issue	From Stakeholder
21	21-06001	At 126, para. 315	NV Energy's rejection of NWAs based upon lead time conflicts with its mandate to consider a six-year period in its DRP pursuant to NAC 704.9237(2)(f) and fails to consider the benefits of NWAs.	Vote Solar
22	21-06001	At 126, para. 316	NV Energy should issue a Request for Information or Request for Proposals for aggregation services that can cost-effectively relieve grid constraints identified in the DRP.	Vote Solar
23	21-06001	At 126, para. 316	NV Energy should incorporate NWAs into its internal distribution planning process so that timing is never used as a basis to not purse cost-effective NWAs in the future.	Vote Solar
24	21-06001	At 126, para. 316	NV Energy should amend its Red Flag Screening Criteria (within the NWA Suitability/Screening Criteria) and remove or deprioritize screening criteria that has not been sufficiently justified.	Vote Solar
25	21-06001	At 126-7, para. 317	NV Energy's NWA methodology attempts to optimize a portfolio of NWAs based on their gross costs and then only calculates the locational net benefits for the selected portfolio of nonwired options.	Vote Solar
26	21-06001	At 127, para. 318	Assertion that the Nevada Legislature did not intend for the utility to own any of the distributed resources in a DRP.	Vote Solar
27	21-06001	At 128, para. 320	Assertion that NV Energy cannot, under the applicable laws, undertake traditional infrastructure upgrades where it has not first demonstrated that the wired solution is preferable based on the net benefits of the NWA.	Vote Solar
28	21-06001	At 128, para. 321	Criterion outside the scope of a net benefit analysis conflict with NAC 704.9237(3)(c), which requires determining "the preferred solution" based on "the locational net benefit analysis of resource options to utility customers."	Vote Solar
29	21-06001	At 128-9, para. 322	Criterion C in NV Energy's NWA Suitability/Screening Criteria effectively shortens the required six-year planning period contemplated by NAC 704.9237(f).	Vote Solar
30	21-06001	At 129, para. 323	Concerns with Criterion D in NV Energy's NWA Suitability/Screening Criteria that provides that an NWA solution must be considered reliable and safe to be considered an option to address an existing or forecasted restraint.	Vote Solar
31	21-06001	At 129, para. 324	Concerns with Criteria E and F in NV Energy's NWA Suitability/Screening Criteria that addresses the fact that residents and/or governmental entities have expressed opposition to the installation of certain NWA technologies.	Vote Solar
32	21-06001	At 129, para. 325	Concerns with Criterion H in NV Energy's NWA Suitability/Screening Criteria that addresses the fact that there may be physical limitations in citing certain NWA technologies in some locations.	Vote Solar
33	21-06001	At 130, para. 326	Critique of how NV Energy's NWA assessment utilizes net benefits in comparing conventional "wired" infrastructure investments with NWAs.	Vote Solar
34	21-06001	At 130, para. 327	Assertion that because net benefits are only calculated by NV Energy for the pre-determined portfolio, the net positive benefits of BESS are minimized and the net positive benefits of solar are completely ignored, constituting a fundamental error in methodology.	Vote Solar
35	21-06001	At 130, para. 328	Concern that NV Energy's net benefit analysis only accounts for the value of energy production or arbitrage and generating capacity benefits of distributed energy resources, which leaves out the benefits of DERs other than energy and production capacity.	Vote Solar

DOCKET NO. 21-06001: DRP STAKEHOLDER PROCESS INITIAL ISSUES LIST

No.	Docket No.	Reference[1]	Issue	From Stakeholder
36	21-06001	At 130, para. 329	Concern that NV Energy assumed only utility-owned and utility-scale models for solar PV and BESS NWAs and contention that assuming utility-scale solar PV and BESS is contrary to the goals of SB 146 and the definition of"distributed generation system" in NRS 701.380(2)(a).	Vote Solar
37	21-06001	At 131, para. 330	NV Energy should seek aggregation services for behind the meter solar and solar plus storage systems from third parties as well as examine market incentives to encourage customer-sited solar and storage deployment in geographically targeted areas.	Vote Solar
38	21-06001	At 131, para. 331	NV Energy could provide incentives for installation of behind the meter solar and BESS with temporal or geographical conditions that could spur deployment in the locations where it has identified grid constraints, potentially becoming a very low-cost NWA.	Vote Solar

[1] From Docket No. 21-06001 March 8, 2022 Corrected Modified Final Order, or Docket No. 22-09001 November 9, 2022 Order.

DRP UPDATE-2

NEVADA POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NE	Allen	ALN BK 1		21.2	22.0	18.9	17.2	16.5
NE	Allen	ALN BK 2//3		61.2	63.9	58.4	55.7	58.9
NE	Allen		ALN1201	322	328	318	294	299
NE	Allen		ALN1203	515	527	486	460	486
NE	Allen		ALN1204	198	176	127	63	1
NE	Allen		ALN1205	419	433	411	400	407
NE	Allen		ALN1206	474	472	441	416	418
NE	Allen		ALN1210	2	2	2	2	2
NE	Allen		ALN1212	463	476	424	400	400
NE	Allen		ALN1213	507	521	475	446	457
NE	Allen		ALN1214	536	546	504	481	491
NE	Allen		ALN1215	401	421	415	403	393
NE	Allen		ALN1217	213	220	197	190	201
NE	Alta	AL BK 3		24.6	25.8	20.8	20.1	21.4
NE	Alta	AL BK 4		11.8	11.7	11.1	10.2	11.5
NE	Alta	AL BK 5		28.8	30.1	28.2	28.0	27.9
NE	Alta	AL BK 6		5.5	4.4	5.2	4.7	4.7
NE	Alta		AL1202	495	508	475	464	466
NE	Alta		AL1203	427	448	281	283	280
NE	Alta		AL1205	293	287	267	273	249
NE	Alta		AL1208	132	94	92	98	95
NE	Alta		AL1209	473	482	457	434	463
NE	Alta		AL1210	356	369	371	358	374
NE	Alta		AL1212	369	383	352	320	314
NE	Alta		AL1213	343	339	339	312	328
NE	Alta		AL1214	317	325	325	328	356
NE	Alta		AL1217	44	42	52	52	45
NE	Alta		AL1218	221	179	201	189	188
NE	Andrews	AND BK 1//2		49.8	49.5	46.9	41.4	43.7
NE	Andrews		AND1203	1	1	1	1	1
NE	Andrews		AND1204	375	355	346	398	400
NE	Andrews		AND1207	441	425	414	398	406
NE	Andrews		AND1209	506	498	331	312	311
NE	Andrews		AND1212	431	420	467	408	415
NE	Andrews		AND1213	199	197	191	178	180
NE	Andrews		AND1214	1	1	1	1	1
NE	Andrews		AND1215	1	1	1	1	1
NE	Andrews		AND1217	475	491	556	438	412
NW	Angel Peak	AP BK 1		0.5	0.4	0.4	0.5	0.5
NW	Angel Peak	AP BK 2		0.0	0.0	0.0	0.0	0.0
NW	Angel Peak		AP3402	21	21	22	22	22
NW	Angel Peak		AP401	24	21	21	21	22
NW	Angel Peak		AP402	16	16	16	16	16
NW	Angel Peak		AP403	30	20	27	35	37

All values in MVA for transformers
All values in amps for feeders

NEVADA POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SE	Anthem	ANT BK 1//2		60.0	66.0	61.0	57.3	60.4
SE	Anthem	ANT BK 3		8.2	9.4	8.7	8.5	8.9
SE	Anthem		ANT1201	402	414	386	368	373
SE	Anthem		ANT1203	142	152	148	144	144
SE	Anthem		ANT1204	494	533	488	457	486
SE	Anthem		ANT1205	427	448	396	380	404
SE	Anthem		ANT1207	501	484	479	463	442
SE	Anthem		ANT1209	177	198	184	178	189
SE	Anthem		ANT1212	492	504	448	427	432
SE	Anthem		ANT1213	374	420	377	358	367
SE	Anthem		ANT1214	420	445	405	396	413
SW	Arden	AD BK 4//5		56.3	51.5	41.5	37.8	36.4
SW	Arden		AD1202	287	249	214	171	171
SW	Arden		AD1203	435	477	414	393	401
SW	Arden		AD1204	370	295	298	369	370
SW	Arden		AD1205	459	376	308	311	281
SW	Arden		AD1206	310	300	260	126	122
SW	Arden		AD1207	482	637	429	397	402
SW	Arden		AD1208	294	130	100	74	1
NE	Artesian	AR BK 2		28.0	31.6	29.3	25.0	24.7
NE	Artesian	AR BK 3//4		55.8	50.3	47.9	48.8	48.9
NE	Artesian		AR1202	231	236	228	213	213
NE	Artesian		AR1203	383	371	289	134	128
NE	Artesian		AR1204	275	455	490	443	431
NE	Artesian		AR1206	441	445	433	403	431
NE	Artesian		AR1208	360	374	375	376	370
NE	Artesian		AR1210	407	233	173	192	229
NE	Artesian		AR1211	433	439	495	488	477
NE	Artesian		AR1213	490	506	475	474	477
NE	Artesian		AR1214	436	440	429	418	431
NE	Artesian		AR1215	452	441	411	403	417
SW	Avera	AVR BK 1		46.7	44.2	45.2	42.2	42.6
SW	Avera	AVR BK 2		33.4	34.1	29.9	31.7	33.6
SW	Avera		AVR1205	479	509	534	475	460
SW	Avera		AVR1206	452	481	426	304	298
SW	Avera		AVR1208	465	500	468	436	429
SW	Avera		AVR1209	528	338	397	376	381
SW	Avera		AVR1210	311	323	295	440	421
SW	Avera		AVR1215	440	570	435	413	433
SW	Avera		AVR1216	412	377	347	329	336
SW	Avera		AVR1217	340	333	321	499	497
SW	Avera		AVR1221	403	387	319	308	312
SE	Balboa	BL BK 1		18.0	18.2	17.7	17.0	18.1
SE	Balboa	BL BK 2//3		32.4	36.0	32.6	31.9	32.8

All values in MVA for transformers
All values in amps for feeders

NEVADA POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SE	Balboa		BL1201	182	192	184	178	194
SE	Balboa		BL1203	447	453	448	436	459
SE	Balboa		BL1204	208	208	202	190	207
SE	Balboa		BL1207	372	338	348	340	353
SE	Balboa		BL1208	319	510	441	411	384
SE	Balboa		BL1209	184	201	186	178	197
SE	Balboa		BL1210	193	197	193	193	190
SE	Balboa		BL1211	438	429	421	377	408
NW	Beltway	BLT BK 3//4		36.2	32.3	28.4	24.0	24.0
NW	Beltway		BLT1213	224	233	228	205	197
NW	Beltway		BLT1214	128	140	135	103	86
NW	Beltway		BLT1216	254	184	16		
NW	Beltway		BLT1217	127	47	9	1	
NW	Beltway		BLT1218	288	229	313	194	153
NW	Beltway		BLT1219	429	444	418	402	428
NW	Beltway		BLT1223	260	278	264	256	255
SE	Bicentennial	BCT BK 1//2		66.6	64.5	56.7	51.3	52.0
SE	Bicentennial		BCT1201	245	169	152	54	41
SE	Bicentennial		BCT1203	415	422	370	357	393
SE	Bicentennial		BCT1204	404	404	366	354	361
SE	Bicentennial		BCT1205	518	521	465	438	454
SE	Bicentennial		BCT1210	236	237	215	216	221
SE	Bicentennial		BCT1211	271	274	245	235	261
SE	Bicentennial		BCT1213	17	22	17	14	8
SE	Bicentennial		BCT1214	310	312	285	269	285
SE	Bicentennial		BCT1215	213	212	191	185	178
SE	Bicentennial		BCT1217	502	497	339	308	218
SE	Big Bend	BGB BK 1		5.1	5.0	6.6	6.7	6.7
SE	Big Bend	BGB BK 2		10.9	11.4	13.0	13.0	13.1
SE	Big Bend		BGB2501	125	119	155	156	156
SE	Big Bend		BGB2507	266	270	301	304	304
NE	Blade Runner	BLR BK 1		0.0	0.0	0.0	0.0	0.0
NE	Blade Runner		BLR1202	24	26	32	24	24
SW	Blue Diamond	BD BK 2//3		0.0	0.0	0.0	0.0	0.0
SW	Blue Diamond		BD401	1	1	1	1	1
SW	Blue Diamond		BD402	1	1	1	1	1
SW	Blue Diamond		BD403	1	1	1	1	1
SW	Blue Diamond		BD404	1	1	1	1	1
SE	Boulder Beach	BB BK 1		0.0	0.0	0.0	0.0	0.0
SE	Boulder Beach		BB1201	89	92	80	69	91
SE	Burnham	BRN BK 1//2		50.3	51.5	50.8	50.8	52.6
SE	Burnham	BRN BK 3		23.3	24.4	23.2	23.6	23.6
SE	Burnham		BRN1201	336	357	338	317	337
SE	Burnham		BRN1202	401	428	439	425	448

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SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SE	Burnham		BRN1204	401	438	438	408	427
SE	Burnham		BRN1205	358	350	323	338	333
SE	Burnham		BRN1206	280	266	304	279	309
SE	Burnham		BRN1209	427	403	397	418	387
SE	Burnham		BRN1210	227	234	213	217	207
SE	Burnham		BRN1211	327	360	360	324	386
SE	Burnham		BRN1212	407	446	400	390	393
SE	Burnham		BRN1214	385	355	373	412	386
SE	Cabana	CB BK 1//2		54.7	63.2	59.3	54.9	54.1
SE	Cabana	CB BK 3		22.8	23.7	25.0	23.9	22.8
SE	Cabana		CB1201	359	382	374	378	342
SE	Cabana		CB1202	240	399	401	397	410
SE	Cabana		CB1204	540	564	526	530	480
SE	Cabana		CB1205	442	475	447	442	411
SE	Cabana		CB1206	250	241	164	149	133
SE	Cabana		CB1209	532	541	497	505	481
SE	Cabana		CB1210	415	457	448	451	413
SE	Cabana		CB1211	409	426	429	433	434
SE	Cabana		CB1212	230	247	296	298	295
SE	Cabana		CB1214	492	515	496	490	398
SE	Cactus	CCT BK 1//2		38.4	40.4	36.4	35.5	34.1
SE	Cactus		CCT1201	1	1	1	1	1
SE	Cactus		CCT1202	340	368	320	308	295
SE	Cactus		CCT1207	405	408	386	390	432
SE	Cactus		CCT1209	1	1	1	1	1
SE	Cactus		CCT1211	466	481	446	420	377
SE	Cactus		CCT1212	355	358	314	282	289
SE	Cactus		CCT1214	256	275	307	310	278
SE	Cactus		CCT1216	1	1	1	1	1
SE	Cactus		CCT1217	1	1	1	1	1
SE	Cactus		CCT1218	1	1	1	1	1
SW	Camero	CMO BK 2		18.1	17.3	17.2	16.1	16.4
SW	Camero		CMO1201	1	1	1	1	1
SW	Camero		CMO1205	352	351	322	351	340
SW	Camero		CMO1206	393	373	364	332	311
SW	Camero		CMO1212	130	140	130	138	140
SW	Camero		CMO1213	1	1	1	1	1
NW	Canyon	CN BK 1		0.0	0.0	0.0	0.0	0.0
NW	Canyon		CN3401	28	27	28	24	29
NE	Carey	CA BK 5		8.2	7.9	7.4	6.0	5.9
NE	Carey	CA BK 6//7		30.5	30.2	28.7	29.0	29.6
NE	Carey	CA BK 8//9		16.2	16.8	15.2	15.3	15.4
NE	Carey		CA1201	145	139	129	126	134
NE	Carey		CA1203	243	236	233	176	145

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NEVADA POWER COMPANY 2018-2022
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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NE	Carey		CA1204	1	1	1	1	1
NE	Carey		CA1207	340	332	329	320	323
NE	Carey		CA1208	246	238	233	228	210
NE	Carey		CA1209	187	198	196	203	199
NE	Carey		CA1211	402	410	383	375	396
NE	Carey		CA1212	290	283	269	248	248
NE	Carey		CA1213	286	304	272	267	260
NE	Carey		CA1215	353	363	324	314	328
NE	Carey		CA1220	142	144	145	152	148
NE	Carey		CA1221	4	3	3	3	3
NW	Charleston	CHR BK 1		12.2	12.8	12.5	11.9	12.4
NW	Charleston		CHR1201	328	344	347	336	311
NW	Charleston		CHR1202	255	275	261	246	261
NW	Cheyenne	CHN BK 1//2		52.9	56.6	52.2	49.7	52.3
NW	Cheyenne	CHN BK 3		19.6	19.5	18.2	17.8	19.1
NW	Cheyenne		CHN1202	493	430	438	418	409
NW	Cheyenne		CHN1204	428	447	426	406	401
NW	Cheyenne		CHN1205	396	411	394	391	411
NW	Cheyenne		CHN1207	484	585	541	507	468
NW	Cheyenne		CHN1208	471	561	467	446	481
NW	Cheyenne		CHN1210	264	282	281	280	288
NW	Cheyenne		CHN1211	428	407	375	360	381
NW	Cheyenne		CHN1212	426	471	450	448	421
NW	Cheyenne		CHN1214	117	119	138	131	136
STRIP	Claymont	CM BK 1		21.3	18.4	16.8	18.2	19.4
STRIP	Claymont	CM BK 2		23.7	24.4	23.3	23.1	22.7
STRIP	Claymont	CM BK 3		19.5	19.9	19.1	20.4	21.5
STRIP	Claymont	CM BK 4		19.1	17.9	19.8	19.9	17.8
STRIP	Claymont		CM1202	131	141	119	121	115
STRIP	Claymont		CM1204	479	406	388	380	393
STRIP	Claymont		CM1205	398	393	383	384	405
STRIP	Claymont		CM1209	463	468	448	427	431
STRIP	Claymont		CM1211	356	377	366	349	359
STRIP	Claymont		CM1212	299	305	290	310	284
STRIP	Claymont		CM1223	271	290	295	296	304
STRIP	Claymont		CM1224	367	387	376	377	399
STRIP	Claymont		CM1225	293	316	312	271	290
STRIP	Claymont		CM1228	366	382	350	349	341
STRIP	Claymont		CM1229	213	214	297	205	231
STRIP	Claymont		CM1230	96	68	101	101	92
STRIP	Claymont		CM1231	256	235	272	272	249
NW	Cold Creek	CC BK 2		5.1	5.0	4.8	5.1	5.4
NW	Cold Creek		CC1202	123	107	108	113	121
NW	Cold Creek		CC1206	126	132	132	135	135

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SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
STRIP	Commerce	COM BK 1		10.6	5.9	12.8	12.0	13.2
STRIP	Commerce	COM BK 2		23.2	15.9	20.0	17.4	18.7
STRIP	Commerce		COM1203	1	1	1	1	1
STRIP	Commerce		COM1204	1	1	1	1	1
STRIP	Commerce		COM1205	249	202	294	295	337
STRIP	Commerce		COM1207	266	272	334	276	311
STRIP	Commerce		COM1216	447	177	330	336	411
STRIP	Commerce		COM1218	141	124	137	109	108
STRIP	Commerce		COM1219	520	542	482	462	413
STRIP	Concourse	CON BK 1		20.7	21.5	23.7	21.4	22.4
STRIP	Concourse	CON BK 2//3		38.5	37.8	35.0	35.9	39.7
STRIP	Concourse		CON1201	363	366	383	341	343
STRIP	Concourse		CON1203	386	419	432	420	449
STRIP	Concourse		CON1204	259	256	292	275	278
STRIP	Concourse		CON1205	306	358	338	341	393
STRIP	Concourse		CON1206	394	408	432	389	431
STRIP	Concourse		CON1209	87	104	149	148	161
STRIP	Concourse		CON1211	358	361	295	300	305
STRIP	Concourse		CON1212	4	4	4	4	4
STRIP	Concourse		CON1213	228	220	208	208	228
STRIP	Concourse		CON1214	2	2	2	2	2
STRIP	Concourse		CON1215	171	124	136	149	142
STRIP	Concourse		CON1217	350	367	310	307	369
NE	Craig	CR BK 1//2		52.7	53.3	50.7	42.6	41.5
NE	Craig	CR BK 3		27.2	28.0	25.9	25.0	28.4
NE	Craig		CR1201	356	361	334	324	319
NE	Craig		CR1203	537	439	438	401	440
NE	Craig		CR1204	479	476	408	347	330
NE	Craig		CR1205	326	330	318	334	345
NE	Craig		CR1206	262	233	210	210	190
NE	Craig		CR1208	434	488	533	461	269
NE	Craig		CR1209	243	250	242	191	199
NE	Craig		CR1211	415	424	395	376	517
NE	Craig		CR1212	509	527	466	435	431
NE	Craig		CR1213	417	401	412	416	423
NE	DeBuono	DEB BK 1		15.1	17.6	13.9	13.7	14.2
NE	DeBuono	DEB BK 2//3		32.4	32.6	30.7	33.1	32.2
NE	DeBuono		DEB1203	351	478	317	289	284
NE	DeBuono		DEB1204	346	340	365	353	371
NE	DeBuono		DEB1210	291	297	306	292	306
NE	DeBuono		DEB1214	399	417	394	385	386
NE	DeBuono		DEB1215	404	423	402	388	430
NE	DeBuono		DEB1216	409	438	407	504	386
SW	Decatur	DE BK 3//7		32.6	31.8	25.6	30.1	31.5

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SW	Decatur	DE BK 4//5		26.1	27.0	24.5	23.9	23.8
SW	Decatur		DE1201	277	295	288	294	296
SW	Decatur		DE1203	314	316	347	319	324
SW	Decatur		DE1204	451	404	371	372	407
SW	Decatur		DE1205	18	19	19	17	18
SW	Decatur		DE1206	291	309	281	266	252
SW	Decatur		DE1209	427	448	398	385	423
SW	Decatur		DE1212	506	538	471	454	442
SW	Decatur		DE1214	473	466	468	446	445
SW	Durango	DU BK 1		21.5	28.5	26.6	25.1	25.5
SW	Durango	DU BK 2//3		50.2	50.5	45.6	43.9	45.6
SW	Durango		DU1201	448	520	472	460	474
SW	Durango		DU1203	493	543	492	466	496
SW	Durango		DU1204	376	366	360	364	362
SW	Durango		DU1205	66	54	23	22	37
SW	Durango		DU1208	498	592	571	547	486
SW	Durango		DU1209	541	558	517	500	508
SW	Durango		DU1210	503	545	506	465	467
SW	Durango		DU1211	401	442	383	380	402
SW	Durango		DU1212	423	525	468	449	476
SW	Durango		DU1215	5	5	5	5	5
NW	El Capitan	ELC BK 1		42.7	41.9	37.9	35.5	37.5
NW	El Capitan	ELC BK 2		43.6	43.7	40.3	39.5	41.2
NW	El Capitan		ELC1204	271	267	248	226	252
NW	El Capitan		ELC1205	340	321	311	259	220
NW	El Capitan		ELC1208	500	465	415	365	424
NW	El Capitan		ELC1209	433	463	435	404	426
NW	El Capitan		ELC1210	465	489	457	439	436
NW	El Capitan		ELC1215	469	482	469	457	491
NW	El Capitan		ELC1216	458	459	434	421	459
NW	El Capitan		ELC1217	525	517	492	520	419
NW	El Capitan		ELC1218	365	378	264	292	302
NW	El Capitan		ELC1220	1	1	1	1	1
NW	El Capitan		ELC1221	259	259	258	248	242
STRIP	El Rancho	ER BK 1		10.7	10.9	10.3	10.1	11.0
STRIP	El Rancho	ER BK 2//3		19.1	18.2	16.1	13.7	17.7
STRIP	El Rancho		ER1201	230	235	254	230	259
STRIP	El Rancho		ER1203	274	279	260	240	278
STRIP	El Rancho		ER1205	271	221	67	68	58
STRIP	El Rancho		ER1207	77	86	96	96	104
STRIP	El Rancho		ER1209	215	188	218	218	234
STRIP	El Rancho		ER1211	153	156	138	148	166
STRIP	El Rancho		ER1212	215	199	204	212	232
NW	Elkhorn	ELK BK 1//2		64.9	66.7	65.4	59.5	61.0

All values in MVA for transformers
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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NW	Elkhorn	ELK BK 3//4		23.7	23.0	20.8	20.2	21.5
NW	Elkhorn		ELK1201	200	209	194	184	189
NW	Elkhorn		ELK1202	521	520	505	484	515
NW	Elkhorn		ELK1206	356	358	369	348	342
NW	Elkhorn		ELK1208	521	547	508	485	491
NW	Elkhorn		ELK1209	436	443	480	350	399
NW	Elkhorn		ELK1211	511	511	486	458	452
NW	Elkhorn		ELK1212	512	547	509	479	475
NW	Elkhorn		ELK1213	322	342	323	311	323
NW	Elkhorn		ELK1214	390	370	363	355	377
NW	Elkhorn		ELK1216	408	363	309	299	309
STRIP	Excalibur	EX BK 1//2		30.0	26.2	23.1	22.9	22.7
STRIP	Excalibur	EX BK 3//4		23.5	20.6	19.9	19.9	21.4
STRIP	Excalibur		EX1201	322	311	354	355	362
STRIP	Excalibur		EX1203	208	231	216	216	218
STRIP	Excalibur		EX1204	183	198	178	177	190
STRIP	Excalibur		EX1205	343	168	205	205	229
STRIP	Excalibur		EX1206	407	424	338	166	149
STRIP	Excalibur		EX1209	5	5	5	5	5
STRIP	Excalibur		EX1211	245	254	246	247	246
STRIP	Excalibur		EX1212	63	61	3	1	5
STRIP	Excalibur		EX1213	358	331	331	348	360
STRIP	Excalibur		EX1214	176	162	166	166	164
STRIP	Excalibur		EX1215	298	333	248	248	288
SE	Faulkner	FLK BK 3		34.2	35.3	34.0	32.5	33.1
SE	Faulkner	FLK BK 4		40.0	41.0	41.3	41.2	41.7
SE	Faulkner	FLK BK 5		23.0	24.4	22.5	20.7	21.7
SE	Faulkner		FLK1204	467	460	445	437	441
SE	Faulkner		FLK1205	418	432	498	490	485
SE	Faulkner		FLK1206	1	1	1	1	1
SE	Faulkner		FLK1208	422	421	430	428	402
SE	Faulkner		FLK1209	375	390	382	378	363
SE	Faulkner		FLK1210	342	326	328	316	323
SE	Faulkner		FLK1215	432	472	434	418	452
SE	Faulkner		FLK1216	161	168	159	148	148
SE	Faulkner		FLK1217	152	166	158	152	151
SE	Faulkner		FLK1218	320	329	317	272	319
SE	Faulkner		FLK1220	170	173	155	156	153
SE	Faulkner		FLK1221	487	472	441	424	438
SE	Faulkner		FLK1224	186	208	196	205	181
SE	Faulkner		FLK1225	1	1	1	1	1
SE	Faulkner		FLK1226	355	363	337	330	316
SE	Faulkner		FLK1227	545	573	519	487	527
STRIP	Flamingo	FL BK 1		5.5	6.0	6.1	5.6	6.7

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
STRIP	Flamingo	FL BK 2//3		25.5	25.8	27.0	25.9	27.6
STRIP	Flamingo		FL1202	150	154	142	143	166
STRIP	Flamingo		FL1203	123	154	148	122	145
STRIP	Flamingo		FL1206	133	147	170	171	159
STRIP	Flamingo		FL1207	160	147	163	163	158
STRIP	Flamingo		FL1208	199	192	191	191	218
STRIP	Flamingo		FL1209	101	106	112	111	108
STRIP	Flamingo		FL1211	314	332	382	326	315
STRIP	Flamingo		FL1212	337	363	313	325	322
SE	Ford	FRD BK 1		26.9	27.9	26.3	25.3	26.7
SE	Ford	FRD BK 2		39.6	42.6	40.4	38.7	38.3
SE	Ford		FRD1204	431	445	411	390	400
SE	Ford		FRD1208	410	429	388	388	403
SE	Ford		FRD1209	70	74	65	65	63
SE	Ford		FRD1210	376	412	386	369	407
SE	Ford		FRD1216	314	347	309	303	284
SE	Ford		FRD1217	301	332	299	282	288
SE	Ford		FRD1218	482	529	490	467	454
SE	Ford		FRD1220	366	401	380	363	363
SE	Ford		FRD1221	427	461	433	417	436
SW	Frias	FRS BK 1//2		32.5	32.7	31.8	29.7	31.1
SW	Frias	FRS BK 3		32.3	33.2	31.1	29.5	30.9
SW	Frias		FRS1206	447	451	400	349	349
SW	Frias		FRS1210	356	383	362	350	352
SW	Frias		FRS1211	490	524	450	436	465
SW	Frias		FRS1212	521	538	496	480	492
SW	Frias		FRS1214	468	498	464	441	442
SW	Frias		FRS1215	282	298	465	427	419
SW	Frias		FRS1217	496	496	442	405	398
STRIP	Garces	GA BK 2//3		28.2	27.8	26.3	27.2	29.5
STRIP	Garces	GA BK 4		7.0	12.2	6.4	6.1	5.0
STRIP	Garces		GA1201	426	441	454	454	477
STRIP	Garces		GA1202	199	200	198	215	225
STRIP	Garces		GA1204	118	124	125	114	132
STRIP	Garces		GA1205	214	204	176	151	137
STRIP	Garces		GA1206	419	418	449	450	444
STRIP	Garces		GA1209	153	127	188	230	135
STRIP	Garces		GA1210	190	482	162	96	94
STRIP	Garces		GA1211	1	1	1	1	1
NE	Gilmore	GLM BK 1//2		43.4	42.1	37.5	37.3	34.3
NE	Gilmore		GLM1203	64	23			
NE	Gilmore		GLM1204	493	513	488	476	486
NE	Gilmore		GLM1205	594	613	551	530	384
NE	Gilmore		GLM1206	490	371	320	312	309

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NE	Gilmore		GLM1211	504	514	481	459	459
SW	Goodsprings	GS BK 1		0.8	0.8	0.8	0.7	0.7
SW	Goodsprings		GS1201	18	19	18	16	17
SW	Goodsprings		GS1202	21	21	22	20	22
NE	Grand Teton	GTT BK 2		24.0	20.7	16.2	14.0	13.4
NE	Grand Teton		GTT1207	329	495	268	155	147
NE	Grand Teton		GTT1208	100	97	96	90	88
NE	Grand Teton		GTT1212	390	408	431	430	388
NE	Grand Teton		GTT1213	309				
SE	Green Valley	GV BK 1		28.8	28.6	25.8	25.2	24.4
SE	Green Valley	GV BK 2//3		51.4	56.3	57.4	54.3	54.8
SE	Green Valley		GV1201	410	413	390	387	377
SE	Green Valley		GV1203	470	477	391	373	340
SE	Green Valley		GV1204	462	489	446	433	426
SE	Green Valley		GV1207	339	329	319	312	328
SE	Green Valley		GV1208	469	246	239	242	245
SE	Green Valley		GV1209	472	556	587	422	399
SE	Green Valley		GV1210	453	469	452	436	451
SE	Green Valley		GV1211	409	429	421	418	400
SE	Green Valley		GV1212	281	293	311	314	258
SE	Green Valley		GV1214	406	554	483	456	460
SE	Greenway	GNW BK 1//2		33.5	37.5	35.7	34.1	33.8
SE	Greenway		GNW1201	1	1	1	1	1
SE	Greenway		GNW1205	383	387	358	336	354
SE	Greenway		GNW1206	435	435	412	404	406
SE	Greenway		GNW1207	398	410	377	364	344
SE	Greenway		GNW1209	528	550	510	478	485
NE	Gypsum	GYP BK 2		10.6	10.3	10.5	10.7	10.7
NE	Gypsum		GYP1208	291	267	283	285	292
NE	Gypsum		GYP1210	216	238	228	223	205
SE	Haven	HV BK 1		28.1	30.0	27.5	27.9	29.4
SE	Haven	HV BK 2//3		43.3	42.4	44.7	44.3	45.2
SE	Haven		HV1202	414	464	442	410	416
SE	Haven		HV1203	419	404	415	415	538
SE	Haven		HV1204	475	554	479	481	497
SE	Haven		HV1205	269	284	272	264	288
SE	Haven		HV1206	276	286	272	272	282
SE	Haven		HV1209	449	463	494	499	484
SE	Haven		HV1210	157	169	192	194	221
SE	Haven		HV1211	403	382	350	350	401
SE	Haven		HV1212	255	255	265	268	274
SE	Haven		HV1213	234	236	243	245	250
STRIP	Highland	HI BK 1//2		21.8	23.0	25.5	21.6	24.2
STRIP	Highland	HI BK 3		9.2	8.6	9.3	9.3	9.5

All values in MVA for transformers
All values in amps for feeders

NEVADA POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
STRIP	Highland	HI BK 4//5		24.8	21.8	25.9	20.2	20.5
STRIP	Highland	HI BK 6		10.6	7.7	3.1	1.6	0.6
STRIP	Highland	HI BK 8		0.2	0.1	0.0	0.0	0.0
STRIP	Highland		HI1201	145	142	125	132	148
STRIP	Highland		HI1202	222	233	271	245	277
STRIP	Highland		HI1203	189	181	189	189	194
STRIP	Highland		HI1205	202	217	238	238	250
STRIP	Highland		HI1206	314	315	414	300	301
STRIP	Highland		HI1209	5	5	6	6	5
STRIP	Highland		HI1210	106	84	124	125	103
STRIP	Highland		HI1211	330	335	317	341	367
STRIP	Highland		HI1214	170	195	283	167	175
STRIP	Highland		HI1215	128	132	121	112	109
STRIP	Highland		HI1216	269	198	119	1	1
STRIP	Highland		HI1217	153	154	158	169	165
STRIP	Highland		HI1219	11	11	10	9	9
STRIP	Highland		HI1220	304	270	282	259	293
STRIP	Highland		HI1222	7	149	127	88	88
STRIP	Highland		HI1224	167	166	93	118	115
STRIP	Highland		HI1225	181	148	37	3	6
STRIP	Highland		HI1226	186	133	10	43	28
STRIP	Highland		HI1228	148	140	126	63	1
STRIP	Highland		HI1261	5	5	6	1	
STRIP	Highland		HI1263	4	4	4	4	
STRIP	Highland		HI1265	3	3	4	1	
STRIP	Highland		HI1267	4	3	4	1	
NW	Hualapai	HU BK 1//2		55.6	55.7	52.0	51.0	54.8
NW	Hualapai	HU BK 3		19.3	20.0	19.5	19.5	21.4
NW	Hualapai		HU1201	469	567	459	441	440
NW	Hualapai		HU1202	429	446	429	412	414
NW	Hualapai		HU1204	404	418	387	372	375
NW	Hualapai		HU1205	311	322	292	292	305
NW	Hualapai		HU1206	531	490	352	355	397
NW	Hualapai		HU1209	321	337	321	304	331
NW	Hualapai		HU1210	300	312	295	275	275
NW	Hualapai		HU1211	226	235	218	233	229
NW	Hualapai		HU1212	387	399	403	395	402
NW	Hualapai		HU1214	305	316	308	301	398
NW	Indian Springs	IS BK 1		0.0	0.0	0.0	0.0	0.0
NW	Indian Springs	IS BK 2		5.7	5.6	5.1	5.6	5.7
NW	Indian Springs		IS1204	272	260	279	260	263
NW	Indian Springs		IS401	3	3	3	3	3
NW	Indian Springs		IS402	55	47	229	207	210
NW	Indian Springs		IS403	230	232	77	54	50

All values in MVA for transformers
All values in amps for feeders

NEVADA POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NW	Iron Mountain	IMT BK 1//2		56.8	58.7	55.9	53.0	53.8
NW	Iron Mountain		IMT1201	497	533	486	467	483
NW	Iron Mountain		IMT1203	367	393	361	341	340
NW	Iron Mountain		IMT1204	248	266	249	233	245
NW	Iron Mountain		IMT1205	380	396	373	351	362
NW	Iron Mountain		IMT1206	179	166	198	189	166
NW	Iron Mountain		IMT1209	2	2	2	2	2
NW	Iron Mountain		IMT1211	518	536	511	492	494
NW	Iron Mountain		IMT1212	548	570	533	517	511
SW	Jean	JN BK 2		9.6	9.6	9.6	4.5	4.7
SW	Jean		JN1207	194	213	214	216	192
SW	Jean		JN1208	267	254	256	259	252
SE	Keehn	KHN BK 1//2		43.6	41.1	45.0	25.6	21.9
SE	Keehn		KHN1201	260	228	195	183	127
SE	Keehn		KHN1203	6	1	1	1	1
SE	Keehn		KHN1204	78	104	105	47	44
SE	Keehn		KHN1205	39	1	2	5	2
SE	Keehn		KHN1206	303	280	210	185	190
SE	Keehn		KHN1210	502	526	461	316	286
SE	Keehn		KHN1211	367	462	439	373	
SE	Keehn		KHN1212	379	374	180	154	148
SE	Keehn		KHN1213	87	62	77		
SE	Keehn		KHN1214	173	181	138	105	76
SE	Keehn		KHN1215	151	205	234	236	234
SE	Keehn		KHN1217	114	127	128	129	130
SE	Kidwell	KI BK 1		0.0	0.0	0.0	0.0	0.0
SE	Kidwell		KI1201	1	1	56	57	57
SE	Kidwell		KI1202	43	43	44	41	41
NW	Kyle Canyon	KC BK 1		0.0	0.0	0.0	0.0	0.0
NW	Kyle Canyon		KC1201	50	48	60	69	48
SE	Lake Las Vegas	LLV BK 1//2		21.5	21.2	19.0	17.2	17.0
SE	Lake Las Vegas		LLV1201	290	276	210	195	187
SE	Lake Las Vegas		LLV1203	464	463	442	419	417
SE	Lake Las Vegas		LLV1205	189	196	194	189	185
SE	Lake Las Vegas		LLV1206	116	110	106	97	96
SE	Lake Las Vegas		LLV1209	74				
SE	Larson	LRS BK 2		0.0	0.0	0.0	0.0	
NE	Leavitt	LVT BK 1		26.0	27.2	25.8	24.5	24.8
NE	Leavitt	LVT BK 2//3		53.8	55.5	58.8	55.1	57.1
NE	Leavitt		LVT1201	529	542	555	490	478
NE	Leavitt		LVT1203	252	249	250	238	241
NE	Leavitt		LVT1204	487	501	462	413	447
NE	Leavitt		LVT1205	536	575	567	466	427
NE	Leavitt		LVT1206	440	453	406	486	474

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All values in amps for feeders

NEVADA POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NE	Leavitt		LVT1209	290	306	294	287	278
NE	Leavitt		LVT1212	451	489	459	463	464
NE	Leavitt		LVT1213	375	364	316	306	321
NE	Leavitt		LVT1214	31	30	453	487	478
NE	Leavitt		LVT1215	552	447	394	357	364
STRIP	Lewis	LE BK 2		1.1	1.1	0.9	1.0	1.1
STRIP	Lewis		LE402	123	113	90	105	105
STRIP	Lewis		LE404	46	44	43	43	64
NE	Lincoln	LCN BK 1//2		50.4	47.3	44.6	44.3	43.6
NE	Lincoln		LCN1203	327	318	294	275	421
NE	Lincoln		LCN1204	432	406	313	312	290
NE	Lincoln		LCN1205	137	136	128	122	102
NE	Lincoln		LCN1206	295	297	269	264	261
NE	Lincoln		LCN1210	420	412	392	361	374
NE	Lincoln		LCN1212	12	12	12	13	12
NE	Lincoln		LCN1213	552	440	413	401	226
NE	Lincoln		LCN1214	284	294	371	368	339
SW	Lindell	LI BK 1//2		28.8	29.5	29.2	29.3	28.3
SW	Lindell	LI BK 3		14.6	13.4	12.7	12.5	12.3
SW	Lindell		LI1202	398	423	403	407	386
SW	Lindell		LI1204	390	400	378	365	327
SW	Lindell		LI1207	334	344	341	333	330
SW	Lindell		LI1208	33	33	49	49	71
SW	Lindell		LI1211	395	413	396	389	382
SW	Lindell		LI1212	110	3	3	3	3
SW	Lindell		LI1213	212	217	202	199	201
SW	Lindell		LI1220	227	239	251	253	243
SE	Lindquist	LDQ BK 1//2		36.9	38.3	34.3	30.1	35.1
SE	Lindquist		LDQ1203	373	368	342	324	334
SE	Lindquist		LDQ1204	252	260	257	258	274
SE	Lindquist		LDQ1205	387	429	365	286	268
SE	Lindquist		LDQ1208	270	292	261	246	251
SE	Lindquist		LDQ1210	281	250	263	266	302
SE	Lindquist		LDQ1215	278	297	261	248	258
NW	Lone Mountain	LMT BK 1//2		33.6	33.3	32.2	30.0	31.2
NW	Lone Mountain		LMT1203	500	529	478	466	499
NW	Lone Mountain		LMT1204	474	495	461	442	472
NW	Lone Mountain		LMT1211	1.01	0.99	0.99	1.00	0.99
NW	Lone Mountain		LMT1213	169	165	142	97	51
NW	Lone Mountain		LMT1215	423	425	418	396	429
NW	Lorenzi	LO BK 1//2		64.5	66.8	62.3	61.0	65.3
NW	Lorenzi	LO BK 3		24.8	27.0	26.5	25.7	25.2
NW	Lorenzi		LO1201	461	480	432	420	456
NW	Lorenzi		LO1203	366	387	375	365	385

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SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NW	Lorenzi		LO1204	424	442	431	403	409
NW	Lorenzi		LO1207	523	519	414	411	438
NW	Lorenzi		LO1208	465	477	515	517	502
NW	Lorenzi		LO1209	497	517	495	479	486
NW	Lorenzi		LO1210	335	354	339	328	354
NW	Lorenzi		LO1211	474	542	544	527	502
NW	Lorenzi		LO1212	302	311	292	286	292
NW	Lorenzi		LO1214	406	420	410	389	396
STRIP	Lynnwood	LY BK 1//2		31.1	32.2	25.1	25.5	28.4
STRIP	Lynnwood		LY1202	493	453	299	214	251
STRIP	Lynnwood		LY1204	329	342	352	352	368
STRIP	Lynnwood		LY1205	236	238	208	217	233
STRIP	Lynnwood		LY1208	335	332	339	340	366
STRIP	Lynnwood		LY1209	144	133	80	185	190
SE	Magic Way	MAG BK 1		19.6	19.9	18.6	16.9	11.6
SE	Magic Way		MAG1209	526	535	484	468	324
SE	Magic Way		MAG1210	391	406	398	370	219
STRIP	Mayfair	MA BK 1		0.0	0.0	0.0	0.0	0.0
STRIP	Mayfair	MA BK 2		13.2	13.2	13.7	13.5	15.1
STRIP	Mayfair	MA BK 3//4		30.8	32.4	30.2	30.6	29.2
STRIP	Mayfair		MA1211	292	300	296	279	348
STRIP	Mayfair		MA1212	324	325	338	361	370
STRIP	Mayfair		MA1213	440	429	400	428	434
STRIP	Mayfair		MA1215	355	371	346	346	342
STRIP	Mayfair		MA1216	341	375	464	332	278
STRIP	Mayfair		MA1218	302	334	324	322	344
STRIP	Mayfair		MA401	219	197	213	213	219
STRIP	Mayfair		MA402	287	285	271	291	260
SW	McDonald	MCD BK 3		29.4	29.4	29.0	27.5	27.5
SW	McDonald	MCD BK 4		37.8	38.1	38.1	35.4	35.1
SW	McDonald		MCD1205	189	193	184	191	214
SW	McDonald		MCD1207	315	335	352	334	320
SW	McDonald		MCD1208	381	374	375	342	348
SW	McDonald		MCD1210	516	546	502	467	486
SW	McDonald		MCD1216	410	433	403	385	394
SW	McDonald		MCD1217	415	435	432	415	412
SW	McDonald		MCD1218	290	314	315	318	302
SW	McDonald		MCD1219	291	268	292	264	246
SW	McDonald		MCD1220	409	432	413	367	376
STRIP	MGM	MGM BK 4		9.1	8.3	9.7	9.7	9.6
STRIP	MGM		MGM1216	1	1	1	1	1
STRIP	MGM		MGM1217	155	135	129	137	141
STRIP	MGM		MGM1218	292	266	327	328	315
NW	Michael Way	MW BK 1//2		38.6	38.6	38.6	37.9	39.0

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NW	Michael Way	MW BK 3		17.3	18.1	16.8	16.5	16.8
NW	Michael Way		MW1201	263	263	252	246	245
NW	Michael Way		MW1202	423	392	377	357	360
NW	Michael Way		MW1204	459	459	410	399	436
NW	Michael Way		MW1207	469	468	438	414	423
NW	Michael Way		MW1209	240	239	405	395	398
NW	Michael Way		MW1211	518	518	499	484	485
NW	Michael Way		MW1213	318	326	308	296	294
NE	Miller	MI BK 3//4		29.6	29.3	31.7	30.2	28.2
NE	Miller		MI1202	276	291	244	257	254
NE	Miller		MI1203	297	291	291	250	230
NE	Miller		MI1206	334	291	284	270	284
NE	Miller		MI1207	370	383	360	350	344
NE	Miller		MI1208	172	159	380	363	353
SE	Mission	MS BK 1//4		24.9	24.3	23.8	22.3	21.3
SE	Mission	MS BK 2//3		36.9	37.0	36.7	34.1	34.0
SE	Mission		MS1201	107	95	78	66	60
SE	Mission		MS1203	419	427	415	405	377
SE	Mission		MS1204	322	311	294	278	281
SE	Mission		MS1205	422	438	403	390	400
SE	Mission		MS1206	269	243	238	204	213
SE	Mission		MS1209	401	423	415	407	373
SE	Mission		MS1210	452	439	486	450	446
SE	Mission		MS1212	232	232	206	206	213
SE	Mission		MS1213	204	214	212	214	200
SE	Mission		MS1214	270	203	162	159	154
SW	Mountains Edge	MTE BK 2//3		68.2	71.0	62.3	59.7	62.3
SW	Mountains Edge		MTE1206	329	351	434	409	412
SW	Mountains Edge		MTE1211	507	523	468	424	415
SW	Mountains Edge		MTE1212	466	480	422	383	404
SW	Mountains Edge		MTE1213	465	490	401	458	486
SW	Mountains Edge		MTE1214	371	389	362	323	328
SW	Mountains Edge		MTE1215	516	535	442	364	371
SW	Mountains Edge		MTE1217	541	577	493	462	475
SW	MYS	MYS BK 2//3		52.7	52.9	52.1	38.9	33.8
SW	MYS		MYS1201	1	1	1		
SW	MYS		MYS1205	168	149	88		
SW	MYS		MYS1206	302	294	284	196	
SW	MYS		MYS1207	268	282	310	285	271
SW	MYS		MYS1208	253	240	300	244	242
SW	MYS		MYS1209	372	292	166	39	1
SW	MYS		MYS1212	195	177	227	141	148
SW	MYS		MYS1214	262	249	329	229	181
SW	MYS		MYS1215	1	1	1	1	1

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SW	MYS		MYS1216	209	252	283	229	242
SW	MYS		MYS1218	508	535	574	497	490
SE	National Park Service	NPS BK 1		0.0	0.0	0.0	0.0	0.0
SE	National Park Service		NPS401	17	19	22	22	22
NE	Nellis	NS BK 1//2		22.7	22.3	18.0	19.4	19.0
NE	Nellis	NS BK 3		6.9	6.1	5.8	5.9	6.2
NE	Nellis		NS1203	187	195	175	163	159
NE	Nellis		NS1204	226	232	209	179	160
NE	Nellis		NS1205	378	367	226	323	363
NE	Nellis		NS1206	378	294	270	257	252
NE	Nellis		NS1210	1	1	1	1	1
NE	Nellis		NS1211	317	295	282	271	286
SE	Nelson	NL BK 1		0.0	0.0	0.0	0.0	0.0
SE	Nelson		NL1201	3	3	10	6	11
NE	North Las Vegas	NLV BK 1		18.2	18.6	17.1	17.6	17.3
NE	North Las Vegas	NLV BK 3//4		28.9	29.3	27.4	27.6	26.4
NE	North Las Vegas		NLV1202	452	448	432	429	414
NE	North Las Vegas		NLV1203	419	436	400	387	393
NE	North Las Vegas		NLV1204	194	205	195	186	190
NE	North Las Vegas		NLV1209	313	320	307	297	308
NE	North Las Vegas		NLV1210	461	462	431	424	387
NE	North Las Vegas		NLV1211	398	392	355	383	374
NE	North Las Vegas		NLV1212	23	38	56	57	53
NW	Northwest	NW BK 4		37.1	38.0	36.3	32.4	32.3
NW	Northwest	NW BK 5		37.5	37.1	32.4	29.7	30.6
NW	Northwest		NW1204	439	405	393	261	257
NW	Northwest		NW1205	505	588	565	524	497
NW	Northwest		NW1206	337	321	319	301	296
NW	Northwest		NW1208	466	498	494	451	480
NW	Northwest		NW1209	1	1	1	1	1
NW	Northwest		NW1215	350	224	252	222	217
NW	Northwest		NW1216	484	491	387	354	376
NW	Northwest		NW1217	419	452	404	382	413
NW	Northwest		NW1220	357	390	351	289	281
NW	Northwest		NW1221	173	189	172	151	155
SW	Oasis	OA BK 1		5.3	5.5	5.6	5.4	5.7
SW	Oasis	OA BK 2//3		3.2	4.2	4.4	3.4	3.6
SW	Oasis		OA1203	75	72	82	83	87
SW	Oasis		OA1204	180	193	193	195	203
SW	Oasis		OA1205	76	148	173	74	80
SW	Oasis		OA1206	238	264	264	261	261
NE	Olive	OL BK 1		0.0	0.0	0.0	0.0	0.0
NE	Olive		OL1202	317	327	324	462	462
NE	Olive		OL1203	462	522	474	483	393

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All values in amps for feeders

NEVADA POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
STRIP	Oquendo	OQ BK 1		16.2	16.3	18.1	17.4	17.1
STRIP	Oquendo	OQ BK 2//3		26.1	25.8	27.4	26.9	28.8
STRIP	Oquendo		OQ1203	257	277	294	287	306
STRIP	Oquendo		OQ1204	242	261	302	278	256
STRIP	Oquendo		OQ1206	295	266	248	263	269
STRIP	Oquendo		OQ1209	368	379	339	364	378
STRIP	Oquendo		OQ1210	160	153	146	142	127
STRIP	Oquendo		OQ1211	79	82	84	84	141
STRIP	Oquendo		OQ1213	284	268	303	283	297
STRIP	Oquendo		OQ1214	374	392	406	407	455
NE	Pabco	PBC BK 2		11.7	9.8	9.9	10.1	9.8
NE	Pabco		PBC1206	399	396	402	413	406
NE	Pabco		PBC1208	164	92	72	78	80
STRIP	Pawnee	PA BK 1//2		30.8	32.7	29.1	27.3	27.7
STRIP	Pawnee		PA1202	378	406	284	277	365
STRIP	Pawnee		PA1203	39	1	75	75	32
STRIP	Pawnee		PA1204	334	337	344	318	344
STRIP	Pawnee		PA1206	278	294	297	228	254
STRIP	Pawnee		PA1207	250	324	172	177	193
STRIP	Pawnee		PA1208	221	218	192	203	228
SW	Peace	PCE BK 1//2		36.3	36.9	33.2	37.0	39.4
SW	Peace	PCE BK 3		25.5	25.1	25.7	24.7	24.9
SW	Peace		PCE1201	1	1	1	1	1
SW	Peace		PCE1204	244	258	241	489	441
SW	Peace		PCE1206	392	405	360	344	334
SW	Peace		PCE1209	446	478	463	445	448
SW	Peace		PCE1211	361	369	321	354	373
SW	Peace		PCE1213	278	242	244	245	236
SW	Peace		PCE1214	462	457	510	515	501
SW	Peace		PCE1215	388	407	404	412	380
SW	Peace		PCE1217	343	311	351	317	295
SE	Pearl	PL BK 1		19.2	19.5	16.1	16.4	16.0
SE	Pearl	PL BK 2//3		35.4	37.2	34.5	33.7	33.0
SE	Pearl		PL1201	310	320	222	220	225
SE	Pearl		PL1202	438	469	430	420	433
SE	Pearl		PL1204	152	149	123	120	142
SE	Pearl		PL1206	412	423	386	373	330
SE	Pearl		PL1209	368	387	350	347	347
SE	Pearl		PL1211	246	251	231	193	228
SE	Pearl		PL1213	425	416	413	413	400
SE	Pearl		PL1214	290	314	273	270	264
SE	Pebble	PB BK 1//2		50.3	53.5	47.7	46.8	49.3
SE	Pebble	PB BK 3		29.1	33.1	31.4	24.3	27.6
SE	Pebble		PB1201	492	529	504	488	469

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All values in amps for feeders

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SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SE	Pebble		PB1203	355	369	342	329	315
SE	Pebble		PB1204	202	218	207	200	198
SE	Pebble		PB1205	515	542	512	478	475
SE	Pebble		PB1209	412	430	390	390	382
SE	Pebble		PB1210	434	458	436	426	427
SE	Pebble		PB1211	403	418	388	374	387
SE	Pebble		PB1212	506	546	522	508	520
SE	Pebble		PB1213	528	592	522	494	505
NE	Pecos	PE BK 6//7		38.9	44.1	39.6	31.3	33.5
NE	Pecos		PE1201	168	168	208	116	89
NE	Pecos		PE1202	62	71	114	69	38
NE	Pecos		PE1207	550	571	466	422	414
NE	Pecos		PE1208	341	571	524	323	347
NE	Pecos		PE1209	484	498	417	461	484
NE	Pecos		PE1211	63				
NE	Pecos		PE1212	294	234	217	205	217
STRIP	Polaris	POL BK 1//2		32.6	33.3	29.3	33.1	35.3
STRIP	Polaris	POL BK 3		22.0	21.7	20.7	20.7	20.0
STRIP	Polaris		POL1201	169	182	185	170	191
STRIP	Polaris		POL1203	408	379	372	386	413
STRIP	Polaris		POL1204	254	264	327	326	285
STRIP	Polaris		POL1205	108	123	115	115	115
STRIP	Polaris		POL1208	1	1	1	1	1
STRIP	Polaris		POL1209	2	1	2	2	2
STRIP	Polaris		POL1210	98	84	82	87	91
STRIP	Polaris		POL1211	268	272	259	283	367
STRIP	Polaris		POL1212	282	301	312	313	393
STRIP	Polaris		POL1213	480	483	381	407	399
STRIP	Polaris		POL1215	446	453	478	479	466
STRIP	Polaris		POL1216	152	140	118	118	182
NE	Prince	PR BK 1//2		32.9	35.6	33.0	35.4	37.8
NE	Prince		PR1202	418	420	393	392	427
NE	Prince		PR1203	101	99	99	140	287
NE	Prince		PR1206	486	502	486	517	532
NE	Prince		PR1207	243	258	251	235	258
NE	Prince		PR1208	404	423	396	367	380
STRIP	Procyon	PRO BK 2		17.6	15.1	19.4	19.5	21.8
STRIP	Procyon	PRO BK 3		6.0	5.9	5.1	0.0	0.0
STRIP	Procyon		PRO1202	355	368	343	361	375
STRIP	Procyon		PRO1206	4	4	4	4	5
STRIP	Procyon		PRO1207	117	118	149	150	160
STRIP	Procyon		PRO1209	151	130	271	59	1
STRIP	Procyon		PRO1211	3	3	321	317	314
STRIP	Procyon		PRO1212	229	208	187	187	243

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All values in amps for feeders

NEVADA POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
STRIP	Procyon		PRO1213	7	7	7	7	16
STRIP	Procyon		PRO1214	148	156	376	61	1
STRIP	Procyon		PRO1216	135	133	105	2	
NE	Prospector	PRS BK 2//3		0.0	0.0	0.0		
SW	Quail	QUL BK 1		24.3	26.3	19.3	19.0	19.4
SW	Quail	QUL BK 2//3		47.2	46.3	46.4	42.4	44.4
SW	Quail		QUL1201	365	393	351	335	336
SW	Quail		QUL1203	333	307	316	301	295
SW	Quail		QUL1204	438	555	248	280	296
SW	Quail		QUL1205	467	480	525	493	477
SW	Quail		QUL1208	483	463	458	416	451
SW	Quail		QUL1209	126	131	126	116	120
SW	Quail		QUL1210	491	504	467	460	472
SW	Quail		QUL1211	289	309	275	281	248
SW	Quail		QUL1212	252	240	223	208	232
SW	Quail		QUL1213	137	121	114	107	100
NW	Radar	RA BK 1		0.0	0.0	0.0	0.0	0.0
NW	Radar		RA1201	6	7	7	8	7
SW	Railroad	RLR BK 1//2		45.4	41.8	40.3	39.3	44.8
SW	Railroad	RLR BK 3		15.7	16.0	16.8	15.8	15.0
SW	Railroad		RLR1201	21	14	31	31	30
SW	Railroad		RLR1203	235	217	205	192	221
SW	Railroad		RLR1204	90	82	59	57	80
SW	Railroad		RLR1205	220	219	206	212	221
SW	Railroad		RLR1206	213	180	190	196	203
SW	Railroad		RLR1210	326	296	264	266	269
SW	Railroad		RLR1211	102	43	43	43	40
SW	Railroad		RLR1212	214	544	453	425	427
SW	Railroad		RLR1214	250	223	212	217	210
SW	Railroad		RLR1215	265	285	291	253	249
SW	Railroad		RLR1217	221	250	292	263	250
SW	Railroad		RLR1218	178	177	182	181	436
SW	Railroad		RLR1219	254	255	320	264	246
NW	Rainbow	RB BK 1//2		34.2	35.9	34.5	32.2	34.1
NW	Rainbow		RB BK 3	19	20	18	18	16
NW	Rainbow		RB1202	300	311	277	243	277
NW	Rainbow		RB1203	426	440	443	420	456
NW	Rainbow		RB1204	339	350	365	323	317
NW	Rainbow		RB1207	249	257	233	216	218
NW	Rainbow		RB1208	295	314	323	324	347
NW	Rainbow		RB1214	106	111	110	104	104
NW	Rainbow		RB1215	451	474	453	463	431
NW	Rainbow		RB1219	346	341	294	271	242
SE	Ranger	RN BK 1		0.0	0.0	0.0	0.0	0.0

All values in MVA for transformers
All values in amps for feeders

NEVADA POWER COMPANY 2018-2022
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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SE	Ranger		RN1201	14	8	8	8	49
SE	Ranger		RN1202	39	35	35	23	55
SW	Red Rock	RRK BK 1//2		44.2	49.7	41.7	41.9	49.8
SW	Red Rock		RRK1201	409	446	427	414	428
SW	Red Rock		RRK1203	346	335	298	278	305
SW	Red Rock		RRK1204	131	346	89	250	459
SW	Red Rock		RRK1211	496	526	451	539	468
SW	Red Rock		RRK1212	374	398	369	360	376
SW	Red Rock		RRK1213	362	372	398	389	316
NW	Regena	RGN BK 2		30.2	31.5	32.3	29.6	32.0
NW	Regena		RGN1201	1	1	1	1	1
NW	Regena		RGN1204	438	461	512	476	498
NW	Regena		RGN1206	87	87	83	82	82
NW	Regena		RGN1210	415	432	426	395	428
NW	Regena		RGN1211	372	395	394	338	372
NW	Regena		RGN1212	121	128	128	118	121
SW	Riley	RLY BK 2//3		35.3	36.0	28.6	28.6	28.6
SW	Riley		RLY1205	467	484	419	384	430
SW	Riley		RLY1206	447	559	475	504	530
SW	Riley		RLY1210	290	152	82	50	
SW	Riley		RLY1211	440	473	420	402	367
SE	River Road	RI BK 1		0.0	0.0	0.0	0.0	0.0
SE	River Road	RI BK 2		4.4	4.4	6.0	5.4	6.0
SE	River Road		RI2501	314	329	327	318	319
SE	River Road		RI2508	108	102	102	98	106
SE	River Road		RI2509	2	2	39	35	35
SW	Robindale	ROB BK 1		20.2	18.9	16.9	16.3	16.4
SW	Robindale	ROB BK 2//3		65.7	68.3	59.5	55.7	56.1
SW	Robindale		ROB1201	526	552	414	394	381
SW	Robindale		ROB1203	172	154	165	162	153
SW	Robindale		ROB1204	288	267	266	267	267
SW	Robindale		ROB1206	359	369	357	330	304
SW	Robindale		ROB1210	524	548	511	493	502
SW	Robindale		ROB1212	366	374	347	328	320
SW	Robindale		ROB1213	419	447	509	486	495
SW	Robindale		ROB1214	390	418	336	337	301
SW	Robindale		ROB1215	547	614	437	380	396
SW	Robindale		ROB1217	481	453	405	385	380
SW	Rosanna	RO BK 1//2		35.3	33.4	30.8	30.5	30.3
SW	Rosanna	RO BK 3		14.7	15.4	14.5	14.2	13.8
SW	Rosanna		RO1201	172	176	155	149	150
SW	Rosanna		RO1203	335	348	322	313	300
SW	Rosanna		RO1204	352	284	251	245	249
SW	Rosanna		RO1207	381	400	351	354	333

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SW	Rosanna		RO1208	468	404	384	377	369
SW	Rosanna		RO1210	354	367	351	352	338
SW	Rosanna		RO1212	331	349	321	311	307
SE	Russell	RS BK 1//2		49.9	50.9	51.6	50.7	48.8
SE	Russell	RS BK 3		22.4	24.4	24.3	24.6	22.7
SE	Russell		RS1201	244	246	225	229	208
SE	Russell		RS1202	157	160	147	148	183
SE	Russell		RS1204	450	460	415	392	356
SE	Russell		RS1205	387	392	401	389	383
SE	Russell		RS1206	417	423	414	398	386
SE	Russell		RS1209	445	461	476	470	440
SE	Russell		RS1210	419	452	482	467	456
SE	Russell		RS1211	459	445	448	433	416
SE	Russell		RS1212	428	518	544	548	474
SE	Russell		RS1214	196	192	172	160	168
SE	Sahara	SA BK 1//4		29.0	29.3	29.1	29.2	29.3
SE	Sahara	SA BK 2//3		33.4	33.8	31.5	30.4	35.1
SE	Sahara		SA1201	402	426	370	370	407
SE	Sahara		SA1203	498	499	531	525	483
SE	Sahara		SA1205	375	401	383	375	397
SE	Sahara		SA1206	406	427	389	346	378
SE	Sahara		SA1209	334	356	332	312	536
SE	Sahara		SA1212	435	449	409	393	359
SE	Sahara		SA1216	402	390	404	394	408
SE	Sahara		SA1217	70	66	67	67	76
STRIP	San Francisco	SF BK 1//2		27.0	25.4	24.3	23.3	24.0
STRIP	San Francisco	SF BK 3//4		27.0	25.9	26.2	25.9	24.2
STRIP	San Francisco		SF1203	275	200	203	192	206
STRIP	San Francisco		SF1204	239	208	144	143	205
STRIP	San Francisco		SF1206	354	332	315	296	301
STRIP	San Francisco		SF1207	447	460	463	450	465
STRIP	San Francisco		SF1213	333	366	349	340	346
STRIP	San Francisco		SF1215	172	177	160	160	197
STRIP	San Francisco		SF1216	271	163	219	220	68
STRIP	San Francisco		SF1217	262	259	255	260	283
STRIP	San Francisco		SF1218	279	247	232	225	254
SE	Searchlight	SE BK 1		0.0	0.0	0.0	0.0	0.0
SE	Searchlight		SE1201	120	129	116	113	123
SE	Searchlight		SE1202	11	7	7	7	6
NE	Shadow	SH BK 3		0.0	0.0	0.0	0.0	0.0
NE	Shadow	SH BK 4//5		29.5	30.2	29.8	30.1	30.8
NE	Shadow		SH1206	260	243	237	255	254
NE	Shadow		SH1207	223	238	228	218	218
NE	Shadow		SH1209	397	403	474	478	470

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NE	Shadow		SH1211	225	226	234	235	232
NE	Shadow		SH1212	332	345	322	314	319
NE	Shadow		SH401	99	82	69	69	75
NE	Shadow		SH404	262	241	223	228	218
NW	Silver Flag	SLV BK 1		0.0	0.0	0.1	0.2	0.2
NW	Silver Flag		SLV1201	4	3	6	10	10
STRIP	Sinatra	SNT BK 1		7.1	7.6	7.6	7.6	8.0
STRIP	Sinatra	SNT BK 2		11.5	11.3	12.8	13.1	13.0
STRIP	Sinatra		SNT1206	174	168	184	184	184
STRIP	Sinatra		SNT1207	4	3	4	4	4
STRIP	Sinatra		SNT1208	166	186	167	169	187
STRIP	Sinatra		SNT1215	143	136	160	161	163
STRIP	Sinatra		SNT1216	185	168	215	215	214
STRIP	Sinatra		SNT1218	209	197	192	208	211
STRIP	Sinatra		SNT1219	14	14	14	14	14
STRIP	Sinatra		SNT1220	14	14	14	15	14
NW	Skelton	SKL BK 1		44.6	46.3	44.5	42.9	44.5
NW	Skelton	SKL BK 2		34.0	34.0	31.7	30.0	32.3
NW	Skelton		SKL1205	418	446	435	406	405
NW	Skelton		SKL1206	406	429	411	398	489
NW	Skelton		SKL1208	479	518	488	481	420
NW	Skelton		SKL1209	460	466	460	451	421
NW	Skelton		SKL1210	380	401	372	355	349
NW	Skelton		SKL1215	375	369	355	347	352
NW	Skelton		SKL1217	232	235	229	210	214
NW	Skelton		SKL1218	395	411	308	301	298
NW	Skelton		SKL1220	216	219	214	199	206
NW	Skelton		SKL1221	414	428	419	412	434
NW	Snow Mountain	SN BK 1		0.0	0.0	0.0	0.0	0.0
NW	Snow Mountain		SN1201	91	91	91	92	92
SE	Southpoint	SO BK 1		0.0	0.0	0.0	0.0	0.0
SE	Southpoint	SO BK 2		0.0	0.0	0.0	0.0	0.0
SE	Southpoint		SO2502	143	143	176	178	171
SE	Southpoint		SO2507	122	124	135	136	125
SE	Southpoint		SO2508	19	12	25	11	8
SW	Sparta	SPA BK 2//3		50.3	50.4	44.3	34.4	33.9
SW	Sparta		SPA1205	508	417	497	461	459
SW	Sparta		SPA1206	490	520	470	443	450
SW	Sparta		SPA1210	396	428	387	370	364
SW	Sparta		SPA1213	202	202	172	4	3
SW	Sparta		SPA1214	281	298	267	236	221
SW	Sparta		SPA1215	254	233	138		
SW	Sparta		SPA1217	268	338	175	131	119
NE	Speedway	SPD BK 1//2		30.8	26.5	23.4	14.9	10.2

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NE	Speedway		SPD1201	250	191	242	162	148
NE	Speedway		SPD1203	282	246	186	125	118
NE	Speedway		SPD1204	198	205	119	112	
NE	Speedway		SPD1206	172	108	1	1	
NE	Speedway		SPD1211	183	177	242	67	70
NE	Speedway		SPD1213	405	391	362	288	209
STRIP	Spencer	SP BK 3		14.0	12.8	12.8	12.6	12.2
STRIP	Spencer	SP BK 4//5		31.7	32.9	29.5	32.5	31.2
STRIP	Spencer		SP1203	292	369	242	242	230
STRIP	Spencer		SP1206	393	377	351	350	350
STRIP	Spencer		SP1207	416	403	396	404	384
STRIP	Spencer		SP1210	299	317	297	307	301
STRIP	Spencer		SP1211	324	350	350	290	248
STRIP	Spencer		SP1213	342	363	341	351	359
STRIP	Spencer		SP1214	175	181	179	163	155
SW	Spring Mountain	SM BK 1		0.0	0.0	0.0	0.0	0.0
SW	Spring Mountain		SM1201	41	39	34	31	44
SW	Spring Mountain		SM1202	180	176	174	178	176
SW	Spring Valley	SV BK 1//4		22.0	22.7	20.2	19.2	19.6
SW	Spring Valley	SV BK 2//3		39.3	42.0	38.6	37.3	35.2
SW	Spring Valley		SV1201	405	395	350	333	324
SW	Spring Valley		SV1202	299	320	280	275	271
SW	Spring Valley		SV1207	266	253	203	190	175
SW	Spring Valley		SV1209	466	540	490	477	428
SW	Spring Valley		SV1211	457	492	464	460	373
SW	Spring Valley		SV1213	277	277	280	280	257
SW	Spring Valley		SV1214	446	486	419	413	410
SW	Spring Valley		SV1216	370	378	356	345	348
STRIP	Strip	STR BK 1		24.1	21.8	23.7	22.5	24.1
STRIP	Strip	STR BK 2		16.2	13.4	15.8	16.6	15.7
STRIP	Strip		STR1203	467	489	443	458	438
STRIP	Strip		STR1204	298	283	291	296	290
STRIP	Strip		STR1205	142	105	207	216	232
STRIP	Strip		STR1206	153	157	152	161	165
STRIP	Strip		STR1207	110	121	127	127	128
STRIP	Strip		STR1208	3	4	4	3	4
STRIP	Strip		STR1215	274	275	252	253	260
STRIP	Strip		STR1216	118	125	127	130	127
STRIP	Strip		STR1217	147	92	26	246	176
STRIP	Strip		STR1218	141	116	231	245	226
STRIP	Strip		STR1219	105	103	190	198	213
NW	Summerlin	SMR BK 1		39.0	40.5	39.1	38.4	40.1
NW	Summerlin	SMR BK 2		36.4	37.3	35.6	33.7	37.2
NW	Summerlin		SMR1205	265	275	266	252	256

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NW	Summerlin		SMR1207	389	414	389	375	375
NW	Summerlin		SMR1208	469	477	462	454	462
NW	Summerlin		SMR1209	412	436	396	377	419
NW	Summerlin		SMR1210	322	335	336	350	343
NW	Summerlin		SMR1217	415	422	402	386	412
NW	Summerlin		SMR1218	415	434	412	391	424
NW	Summerlin		SMR1219	440	446	431	423	454
NW	Summerlin		SMR1220	427	429	416	400	430
SE	Sunset	SUS BK 1//2		28.7	24.9	20.5	21.8	17.3
SE	Sunset		SUS1201	354	309	237	149	
SE	Sunset		SUS1203	65	1	1	1	
SE	Sunset		SUS1205	457	470	291	454	428
SE	Sunset		SUS1206	394	416	470	436	403
SE	Sunset		SUS1212	92	1	1		
STRIP	Suzanne	SZ BK 1//2		44.0	38.6	42.5	38.8	39.2
STRIP	Suzanne	SZ BK 3		15.2	14.5	12.6	11.4	12.6
STRIP	Suzanne		SZ1201	311	221	235	235	270
STRIP	Suzanne		SZ1202	417	433	400	429	431
STRIP	Suzanne		SZ1203	358	333	404	302	297
STRIP	Suzanne		SZ1205	309	365	337	368	386
STRIP	Suzanne		SZ1206	254	262	252	253	279
STRIP	Suzanne		SZ1208	176	146	205	206	204
STRIP	Suzanne		SZ1209	319	265	361	159	185
STRIP	Suzanne		SZ1211	304	327	249	194	170
STRIP	Suzanne		SZ1213	66	43	48	49	55
STRIP	Suzanne		SZ1214	370	357	350	373	406
STRIP	Swenson	SWN BK 1//2		20.2	15.8	15.5	22.5	21.9
STRIP	Swenson	SWN BK 3		13.9	7.4	7.4	0.0	
STRIP	Swenson		SWN1201	258	248	285	285	283
STRIP	Swenson		SWN1206	8				
STRIP	Swenson		SWN1207	3	3	3	3	4
STRIP	Swenson		SWN1208	255	262	254	260	273
STRIP	Swenson		SWN1209	251	254	242	243	221
STRIP	Swenson		SWN1211	194	1	1		
STRIP	Swenson		SWN1213	248	105	117	117	74
STRIP	Swenson		SWN1214	8				
STRIP	Swenson		SWN1216	130	127	17	16	16
STRIP	Swenson		SWN1219	289	278	270	249	202
SW	Tam	TA BK 1		16.9	17.6	16.2	15.2	15.3
SW	Tam	TA BK 2//3		32.7	33.6	33.8	33.6	33.0
SW	Tam		TA1201	405	432	405	387	362
SW	Tam		TA1202	136	123	118	118	122
SW	Tam		TA1204	256	261	242	237	238
SW	Tam		TA1205	385	377	366	367	344

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SW	Tam		TA1209	462	488	471	470	466
SW	Tam		TA1210	396	406	418	417	383
SW	Tam		TA1212	354	370	359	360	390
NW	Tenaya	TE BK 1		18.8	19.2	17.7	16.9	17.6
NW	Tenaya	TE BK 2//3		54.8	57.8	54.0	51.6	53.0
NW	Tenaya		TE1201	444	458	432	371	389
NW	Tenaya		TE1203	189	188	172	174	190
NW	Tenaya		TE1204	268	275	254	269	281
NW	Tenaya		TE1205	284	270	274	247	264
NW	Tenaya		TE1206	485	513	457	433	469
NW	Tenaya		TE1208	152	190	162	163	152
NW	Tenaya		TE1209	528	554	546	527	519
NW	Tenaya		TE1211	418	442	412	400	425
NW	Tenaya		TE1212	413	441	420	407	386
NW	Tenaya		TE1213	386	403	365	353	384
SE	Tolson	TOL BK 3		45.1	46.0	41.8	38.4	41.6
SE	Tolson	TOL BK 4		46.1	49.7	47.2	43.8	44.7
SE	Tolson		TOL1204	487	526	483	436	436
SE	Tolson		TOL1205	510	523	475	461	446
SE	Tolson		TOL1206	442	528	478	461	461
SE	Tolson		TOL1208	482	526	486	465	463
SE	Tolson		TOL1209	318	337	316	306	325
SE	Tolson		TOL1215	470	486	424	413	433
SE	Tolson		TOL1216	448	457	435	404	384
SE	Tolson		TOL1218	157	124	81	47	353
SE	Tolson		TOL1220	500	552	499	478	479
SE	Tolson		TOL1221	523	545	501	474	465
SW	Tomsik	TOM BK 2//3		67.1	68.4	65.0	49.4	52.5
SW	Tomsik		TOM1201	150	135	104	197	189
SW	Tomsik		TOM1203	1	1	1	1	1
SW	Tomsik		TOM1204	422	419	395	390	371
SW	Tomsik		TOM1210	129	126	246	231	218
SW	Tomsik		TOM1211	493	501	480	288	342
SW	Tomsik		TOM1212	449	477	420	404	419
SW	Tomsik		TOM1213	516	534	470	449	462
SW	Tomsik		TOM1214	502	534	450	422	456
SW	Tomsik		TOM1215	1	1	1	1	1
SW	Tomsik		TOM1217	475	503	459	1	1
NE	Tonopah	TO BK 1//2		38.5	38.7	33.9	34.2	33.0
NE	Tonopah	TO BK 3		13.1	13.0	11.8	10.6	12.5
NE	Tonopah		TO1201	435	444	432	425	407
NE	Tonopah		TO1203	477	465	72	73	73
NE	Tonopah		TO1204	408	376	371	366	368
NE	Tonopah		TO1206	510	524	538	536	511

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NE	Tonopah		TO1207	55	56	254	257	254
NE	Tonopah		TO1209	330	325	338	314	357
NE	Tonopah		TO1211	303	302	242	228	286
NE	Tropical	TRO BK 1//2		57.4	53.9	47.3	45.6	47.1
NE	Tropical	TRO BK 3		29.9	29.9	28.2	25.4	25.9
NE	Tropical		TRO1201	511	531	486	453	455
NE	Tropical		TRO1203	270	269	246	242	238
NE	Tropical		TRO1204	370	374	328	272	252
NE	Tropical		TRO1205	570	558	499	467	459
NE	Tropical		TRO1206	469	293	268	444	439
NE	Tropical		TRO1209	1	1	1	1	1
NE	Tropical		TRO1211	382	392	359	342	339
NE	Tropical		TRO1212	194	192	141	30	50
NE	Tropical		TRO1214	460	484	461	447	474
NE	Tropical		TRO1215	466	478	522	474	441
NE	Tropical		TRO1217	482	446	328	309	306
STRIP	Truman	TR BK 1//2		12.2	11.5	14.2	13.9	13.0
STRIP	Truman		TR1202	308	314	422	427	284
STRIP	Truman		TR1209	15	1	1	1	1
STRIP	Truman		TR1210	252	233	236	243	332
STRIP	Valley View	VV BK 1		15.4	13.9	16.9	17.6	15.5
STRIP	Valley View	VV BK 2//3		28.5	31.6	32.2	30.8	32.8
STRIP	Valley View		VV1201	302	212	377	379	303
STRIP	Valley View		VV1203	167	171	170	170	185
STRIP	Valley View		VV1204	273	292	329	329	326
STRIP	Valley View		VV1206	399	372	422	359	361
STRIP	Valley View		VV1207	371	407	379	380	408
STRIP	Valley View		VV1209	227	239	282	278	269
STRIP	Valley View		VV1210	385	535	542	513	523
STRIP	Valley View		VV1212	5	1	18	1	1
NW	Vegas	VGS BK 1//2		51.8	53.8	52.4	49.5	53.7
NW	Vegas	VGS BK 3		23.7	24.8	23.5	22.4	24.1
NW	Vegas		VGS1201	382	397	394	389	384
NW	Vegas		VGS1203	434	456	432	418	412
NW	Vegas		VGS1204	224	225	219	210	209
NW	Vegas		VGS1205	384	410	411	387	387
NW	Vegas		VGS1206	394	412	398	380	412
NW	Vegas		VGS1207	405	442	411	394	404
NW	Vegas		VGS1208	261	290	289	276	305
NW	Vegas		VGS1211	362	379	366	345	361
NW	Vegas		VGS1212	339	371	341	321	331
NW	Vegas		VGS1213	409	412	429	409	432
NW	Village	VLG BK 1		34.4	26.3	33.6	30.9	23.7
NW	Village		VLG1201	423	457	399	384	406

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
NW	Village		VLG1203	253	240	227	198	217
NW	Village		VLG1205	1	1	1		
NW	Village		VLG1206	1	1	162	150	155
NW	Village		VLG1210	248	1	243	220	132
NW	Village		VLG1212	100	119	95	71	69
NW	Village		VLG1213	218	206	202	180	176
NW	Village		VLG1215	87	86	77	88	
NW	Village		VLG1217	385	415	392	281	1
SE	Warmsprings	WSP BK 1//2		47.8	47.3	51.7	42.0	40.5
SE	Warmsprings	WSP BK 3		26.5	24.2	25.4	25.0	28.9
SE	Warmsprings		WSP1201	416	453	441	442	439
SE	Warmsprings		WSP1203	333	326	249	216	224
SE	Warmsprings		WSP1204	379	393	434	435	428
SE	Warmsprings		WSP1205	149	167	194	186	150
SE	Warmsprings		WSP1208	168	176	178	180	155
SE	Warmsprings		WSP1209	452	486	581	313	306
SE	Warmsprings		WSP1210	421	442	441	445	427
SE	Warmsprings		WSP1211	385	502	504	503	561
SE	Warmsprings		WSP1212	394	430	296	293	326
SE	Warmsprings		WSP1213	457	475	417	419	464
NE	Washburn	WSH BK 1		26.6	27.0	29.5	28.8	31.1
NE	Washburn	WSH BK 2//3		63.9	67.4	55.6	54.5	57.6
NE	Washburn		WSH1201	202	216	205	194	193
NE	Washburn		WSH1203	529	539	493	472	489
NE	Washburn		WSH1204	517	539	514	496	510
NE	Washburn		WSH1205	494	517	477	457	497
NE	Washburn		WSH1208	357	371	358	323	315
NE	Washburn		WSH1209	396	401	368	346	369
NE	Washburn		WSH1210	510	543	491	473	503
NE	Washburn		WSH1211	440	451	405	390	419
NE	Washburn		WSH1212	475	490	432	403	400
NE	Washburn		WSH1213	452	472	447	428	453
NE	Washington	WN BK 1//2		35.6	35.7	34.6	32.7	34.6
NE	Washington	WN BK 3//4		33.2	36.4	32.8	33.0	34.2
NE	Washington		WN1201	316	316	308	294	266
NE	Washington		WN1203	445	457	450	431	434
NE	Washington		WN1204	485	508	492	473	445
NE	Washington		WN1206	201	221	199	187	214
NE	Washington		WN1208	253	259	254	248	277
NE	Washington		WN1209	374	375	369	365	386
NE	Washington		WN1210	357	371	349	339	348
NE	Washington		WN1211	475	469	429	414	419
NE	Washington		WN1213	367	500	463	447	470
SE	Water Street	WA BK 1//2		30.1	34.3	29.5	28.5	31.0

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SE	Water Street	WA BK 3		8.5	0.6	0.9	3.4	5.1
SE	Water Street		WA1201	275	240	204	194	200
SE	Water Street		WA1203	1	1	1	1	1
SE	Water Street		WA1204	290	469	353	338	362
SE	Water Street		WA1206	452	469	448	445	476
SE	Water Street		WA1208	402	409	384	386	404
SE	Water Street		WA1209	205	28			
SE	Water Street		WA1210	219	1			
NW	Westside	WE BK 3		10.3	10.3	10.8	10.1	9.7
NW	Westside	WE BK 5		19.3	21.8	19.5	19.4	19.2
NW	Westside	WE BK 6//7		56.3	56.9	54.6	51.8	53.2
NW	Westside		WE1201	454	476	438	430	417
NW	Westside		WE1203	1	1	1	1	1
NW	Westside		WE1204	450	542	500	474	488
NW	Westside		WE1207	482	506	474	455	483
NW	Westside		WE1208	382	360	359	343	338
NW	Westside		WE1209	379	409	382	369	363
NW	Westside		WE1210	448	452	430	432	436
NW	Westside		WE1211	81	82	82	74	76
NW	Westside		WE1212	454	425	414	405	410
NW	Westside		WE1214	487	512	486	465	471
NW	Westside		WE1219	150	138	189	149	138
NW	Westside		WE1220	360	352	337	335	326
SE	Whitney	WH BK 1//2		30.9	32.7	29.5	29.9	29.9
SE	Whitney	WH BK 3//4		28.2	33.7	27.3	26.4	31.1
SE	Whitney		WH1201	285	314	287	353	352
SE	Whitney		WH1202	433	380	358	360	359
SE	Whitney		WH1203	9	8	7	7	6
SE	Whitney		WH1204	324	404	368	374	347
SE	Whitney		WH1206	458	481	391	389	389
SE	Whitney		WH1209	316	334	322	320	306
SE	Whitney		WH1211	369	408	332	321	377
SE	Whitney		WH1213	516	544	513	490	486
SE	Whitney		WH1214	363	360	161	158	320
SE	Wigwam	WI BK 1//2		56.6	58.7	57.7	56.5	58.2
SE	Wigwam	WI BK 3		24.9	25.2	24.3	23.6	25.1
SE	Wigwam		WI1201	299	316	295	295	291
SE	Wigwam		WI1203	472	504	485	460	460
SE	Wigwam		WI1204	488	501	465	453	455
SE	Wigwam		WI1205	497	529	518	499	475
SE	Wigwam		WI1206	380	395	380	369	371
SE	Wigwam		WI1208	189	191	233	233	218
SE	Wigwam		WI1209	433	425	423	423	437
SE	Wigwam		WI1211	315	328	320	312	330

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
SE	Wigwam		WI1212	411	390	369	358	387
SE	Wigwam		WI1213	431	454	437	441	458
SE	Wilson	WIL BK 1		37.4	41.1	38.0	34.1	33.8
SE	Wilson	WIL BK 2		41.3	44.1	40.5	37.5	39.8
SE	Wilson		WIL1204	62	59	51	46	8
SE	Wilson		WIL1205	169	192	177	137	97
SE	Wilson		WIL1206	376	379	335	276	233
SE	Wilson		WIL1208	527	541	492	474	452
SE	Wilson		WIL1209	447	488	454	430	435
SE	Wilson		WIL1210	456	478	414	392	399
SE	Wilson		WIL1215	1	1	1	1	1
SE	Wilson		WIL1216	396	399	342	280	274
SE	Wilson		WIL1217	317	352	322	309	343
SE	Wilson		WIL1218	478	507	477	465	469
SE	Wilson		WIL1220	479	495	479	461	460
SE	Wilson		WIL1221	351	362	326	299	303
SE	Winterwood	WW BK 1//2		36.6	39.1	34.2	32.8	34.4
SE	Winterwood	WW BK 3		12.6	12.9	7.9	7.3	7.1
SE	Winterwood	WW BK 7//8		41.7	37.1	37.5	35.7	34.8
SE	Winterwood		WW1203	465	486	411	402	410
SE	Winterwood		WW1204	431	472	416	392	420
SE	Winterwood		WW1205	157	142	142	141	140
SE	Winterwood		WW1207	507	525	485	463	466
SE	Winterwood		WW1210	179	188	176	172	162
SE	Winterwood		WW1211	364	373	322	292	287
SE	Winterwood		WW1214	272	274	62	63	44
SE	Winterwood		WW1216	379	269	282	282	288
SE	Winterwood		WW1217	437	458	424	410	415
SE	Winterwood		WW1219	555	410	382	376	378
SE	Winterwood		WW1220	382	391	347	330	302
SE	Winterwood		WW1224	269	277	286	278	276
SE	Winterwood		WW1225	97	100	103	98	97

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
EAST	Adobe	ADB BK 1		14.1	14.4	12.3	10.9	11.5
EAST	Adobe	ADB BK 2		11.5	11.7	11.7	11.3	11.0
EAST	Adobe		ADB201	55	53	51	43	48
EAST	Adobe		ADB202	271	274	228	209	213
EAST	Adobe		ADB203	70	68	68	60	60
EAST	Adobe		ADB208	227	239	240	222	233
TM	Airport	AIR BK 2		3.0	3.0	3.0	2.9	3.2
TM	Airport	AIR BK 3		33.3	32.7	31.3	30.8	34.9
TM	Airport	AIR BK 4		32.1	32.1	32.1	31.2	33.1
TM	Airport		AIR1	1	1	1	1	1
TM	Airport		AIR2	1	1	1	1	1
TM	Airport		AIR2006	63	68	68	66	69
TM	Airport		AIR242	117	123	110	110	120
TM	Airport		AIR265	183	196	180	174	229
TM	Airport		AIR266	175	187	180	180	199
TM	Airport		AIR267	411	416	439	419	408
TM	Airport		AIR269	217	219	210	205	199
TM	Airport		AIR282	281	266	251	251	267
TM	Airport		AIR283	93	92	89	84	90
TM	Airport		AIR3	186	192	181	166	211
TM	Airport		AIR4	205	216	223	215	215
EAST	Antelope Valley	ANV BK 1		6.1	6.7	6.7	6.8	6.8
EAST	Antelope Valley	ANV BK 2		5.6	5.3	5.3	4.9	5.0
EAST	Antelope Valley		ANV210	142	154	155	157	157
EAST	Antelope Valley		ANV211	131	122	122	113	115
FF	Austin	AST BK 1		4.4	4.2	3.9	3.5	3.9
FF	Austin		AST201	79	79	72	61	68
FF	Austin		AST202	25	25	22	22	25
EAST	Battle Mountain	BMT BK 2		5.3	5.4	4.7	4.2	4.9
EAST	Battle Mountain	BMT BK 3		1.8	1.8	1.5	1.7	1.3
EAST	Battle Mountain		BMT1401	193	191	181	169	180
EAST	Battle Mountain		BMT1402	20	26	7	7	21
EAST	Battle Mountain		BMT2401	43	43	35	39	30
TM	Bella Vista	BLV BK 1		21.0	21.8	21.7	21.7	23.0
TM	Bella Vista	BLV BK 2		39.7	38.1	35.3	32.8	36.1
TM	Bella Vista		BLV271	404	408	407	404	436
TM	Bella Vista		BLV282	189	201	200	194	206
TM	Bella Vista		BLV283	100	102	102	102	107
TM	Bella Vista		BLV284	730	700	640	574	632
EAST	Big Springs	BSP BK 1		0.0	0.0	0.0	0.0	0.0
EAST	Big Springs		BSP213	1	1	1	1	1
FF	Brady's	BDY BK 1		0.7	0.7	0.7	0.7	0.7
FF	Brady's		BDY201	17	17	17	17	17
CAR	Brunswick	BWK BK 3		8.2	8.0	8.1	8.7	8.0

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
CAR	Brunswick	BWK BK 4		19.0	18.8	17.6	17.1	17.8
CAR	Brunswick		BWK1220	233	222	221	216	217
CAR	Brunswick		BWK1223	193	193	211	225	213
CAR	Brunswick		BWK1224	463	463	421	426	424
CAR	Brunswick		BWK2508	189	186	189	200	186
CAR	Buckeye	BUC BK 2		22.7	21.6	18.7	18.9	21.1
CAR	Buckeye		BUC1275	129	121	117	126	113
CAR	Buckeye		BUC1276	499	416	387	384	404
CAR	Buckeye		BUC1277	130	126	100	95	192
CAR	Buckeye		BUC1278	340	340	288	275	281
EAST	Buena Vista	BVV BK 1		1.8	1.9	1.8	1.7	1.7
EAST	Buena Vista		BVV201	42	43	42	39	38
EAST	Buena Vista		BVV202	1	1	1	1	1
TM	California	CAL BK 1		17.1	14.4	12.3	10.9	12.9
TM	California		CAL2501	397	336	288		
CAR	Carson	CAR BK 1		17.8	17.8	16.3	15.8	15.6
CAR	Carson	CAR BK 2		19.8	19.7	17.9	17.3	17.7
CAR	Carson		CAR1230	134	134	128	122	122
CAR	Carson		CAR1231	402	403	368	347	347
CAR	Carson		CAR1232	287	288	257	272	282
CAR	Carson		CAR1233	1	1	1	1	1
CAR	Carson		CAR1240	179	180	163	152	148
CAR	Carson		CAR1241	171	171	173	171	182
CAR	Carson		CAR1242	270	270	249	251	260
CAR	Carson		CAR1243	317	308	289	254	252
TM	Chukar	CHK BK 1		4.7	15.7	6.0	5.6	13.3
TM	Chukar		CHK2505	241	228			
TM	Chukar		CHK2506	110	140	140	131	309
EAST	Coal Canyon	CCN BK 1		1.7	2.0	2.0	1.9	1.9
EAST	Coal Canyon		CCN1201	62	72	70	70	68
EAST	Coal Canyon		CCN1202	19	22	21	20	21
CAR	Coaldale	CLD BK 1		0.1	0.1	0.1	0.1	0.1
CAR	Coaldale		CLD1201	6	6	6	6	6
EAST	Crescent Valley	CVL BK 1		1.1	1.4	1.2	1.3	1.2
EAST	Crescent Valley		CVL220	26	32	28	29	27
CAR	Curry Street	CUR BK 1		9.9	10.0	9.4	9.5	10.0
CAR	Curry Street	CUR BK 2		9.2	9.2	7.8	8.1	8.1
CAR	Curry Street		CUR1280	428	429	364	373	373
CAR	Curry Street		CUR1281	323	324	294	285	297
CAR	Curry Street		CUR1282	172	173	175	173	172
CAR	Dayton	DTN BK 1		9.9	9.9	8.8	9.0	9.0
CAR	Dayton		DTN219	228	229	205	208	208
CAR	Downs	DWN BK 1		11.8	11.8	10.2	9.8	8.0
CAR	Downs		DWN1285	328	329	293	287	287

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
CAR	Downs		DWN1286	221	221	205	193	111
CAR	Downs		DWN1287	1	1	1	1	1
EAST	Dutch Flat	DHF BK 1		13.1	12.4	11.5	10.4	11.4
EAST	Dutch Flat	DHF BK 2		6.0	6.1	6.1	6.1	5.7
EAST	Dutch Flat		DHF208	304	287	266	242	263
EAST	Dutch Flat		DHF209	94	101	97	93	87
EAST	Dutch Flat		DHF210	45	41	45	49	49
FF	Eagle	EGL BK 2		5.5	5.6	5.2	5.1	5.6
FF	Eagle	EGL BK 3		20.1	19.2	20.6	18.8	18.6
FF	Eagle		EGL1218	255	261	240	235	258
FF	Eagle		EGL201	118	112	174	170	185
FF	Eagle		EGL202	349	342	329	265	246
EAST	Elko	EKO BK 2		0.9	1.3	1.5	1.6	2.0
EAST	Elko		EKO24	127	146	192	232	294
EAST	Elko		EKO27	88	158	160	159	197
CAR	Emerson	EMN BK 1		23.5	23.6	21.5	21.4	22.4
CAR	Emerson		EMN1221	277	278	280	278	272
CAR	Emerson		EMN1222	248	249	249	259	259
CAR	Emerson		EMN1223	356	354	310	316	322
CAR	Emerson		EMN1224	248	233	227	220	220
FF	Empire	EMP BK 1		0.5	0.5	0.5	0.5	0.4
FF	Empire		EMP7001	72	71	72	71	58
CAR	Fairview	FVW BK 1		15.4	15.4	17.2	17.3	17.3
CAR	Fairview		FVW1210	327	346	318	311	327
CAR	Fairview		FVW1211	126	127	121	132	136
CAR	Fairview		FVW1212	276	273	360	372	378
FF	Fallon	FLN BK 1		4.2	4.3	3.9	3.6	2.7
FF	Fallon	FLN BK 2		0.1	0.1	0.1	0.1	1.1
FF	Fallon	FLN BK 3		9.9	10.5	9.1	10.4	11.0
FF	Fallon		FLN1201	235	249	222	256	261
FF	Fallon		FLN1202	195	197	182	165	125
FF	Fallon		FLN1203	223	241	200	227	247
FF	Fallon		FLN309	1	1	1	1	1
FF	Fallon		FLN310	1	1	1	1	18
FF	Fernley	FLY BK 1		17.5	16.3	19.5	13.2	13.6
FF	Fernley		FLY1214	146	138	303	170	161
FF	Fernley		FLY1215	264	245	236	232	254
FF	Fernley		FLY1216	87	77	121	107	101
FF	Fernley		FLY1217	317	317	303	184	202
CAR	Fort Churchill	FTC BK 1		3.6	3.6	4.2	3.2	3.5
CAR	Fort Churchill		FTC210	85	84	97	74	80
TM	Fort Sage	FTS BK 1		2.5	2.6	2.6	2.5	0.1
TM	Fort Sage		FTS299	59	60	60	61	3
CAR	Gabbs	GBS BK 1		3.8	3.8	3.8	3.4	3.6

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
CAR	Gabbs		GBS47	144	144	148	140	120
CAR	Gabbs		GBS48	856	859	812	762	781
STAH	Glenbrook	GLN BK 1		3.7	3.3	3.4	3.3	3.3
STAH	Glenbrook		GLN2302	124	111	118	112	112
STAH	Glenbrook		GLN2505	18	18	18	17	16
STAH	Glenbrook		GLN2600	23	20	18	16	13
TM	Glendale	GLD BK 1		30.3	29.8	28.2	23.7	28.8
TM	Glendale	GLD BK 2		35.6	34.4	34.8	34.4	36.9
TM	Glendale		GLD211	379	378	365	360	369
TM	Glendale		GLD237	99	102	108	108	108
TM	Glendale		GLD238	84	85	91	91	86
TM	Glendale		GLD245	135	142	143	139	147
TM	Glendale		GLD265	135	141	132	129	134
TM	Glendale		GLD271	241	243	226	222	251
TM	Glendale		GLD274	479	451	428	407	425
EAST	Golconda	GOL BK 1		3.0	3.0	3.3	3.2	3.3
EAST	Golconda		GOL1201	51	47	52	45	54
EAST	Golconda		GOL1202	78	82	88	92	100
EAST	Golconda		GOL1203	3	3	3	3	1
CAR	Goldfield	GFD BK 1		1.0	0.9	0.8	0.7	0.5
CAR	Goldfield		GFD1264	46	42	39	34	24
EAST	Grass Valley	GRS BK 1		17.9	18.3	16.5	15.6	15.4
EAST	Grass Valley		GRS2517	241	227	222	203	202
EAST	Grass Valley		GRS2518	194	192	182	166	166
TM	Greg Street	GRG BK 1		27.3	26.5	26.8	24.6	28.7
TM	Greg Street	GRG BK 2		36.3	36.7	33.6	32.2	38.5
TM	Greg Street	GRG BK 3		35.7	35.4	32.5	28.9	27.2
TM	Greg Street		GRG227	148	140	140	64	63
TM	Greg Street		GRG228	382	377	353	337	377
TM	Greg Street		GRG229	356	317	315	302	246
TM	Greg Street		GRG231	226	200	159	154	188
TM	Greg Street		GRG232	229	221	222	205	310
TM	Greg Street		GRG233	399	438	410	414	396
TM	Greg Street		GRG286	276	262	234	190	208
TM	Greg Street		GRG287	152	153	162	153	163
TM	Greg Street		GRG288	251	248	260	255	296
CAR	Hawthorne	HAW BK 1		5.7	5.6	5.4	5.4	5.1
CAR	Hawthorne		HAW1201	121	124	124	123	107
CAR	Hawthorne		HAW1202	145	145	140	130	130
FF	Hazen	HAZ BK 1		0.3	0.3	0.3	0.2	0.3
FF	Hazen		HAZ1210	13	13	12	11	12
CAR	Heybourne	HEY BK 1		11.9	11.9	13.0	12.4	13.0
CAR	Heybourne		HEY1287	273	273	247	241	245
CAR	Heybourne		HEY1288	242	242	324	285	314

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
CAR	Heybourne		HEY1289	1	1	1	1	1
CAR	Heybourne		HEY1290	73	73	64	67	67
TM	Highland^	HLD BK 1		1.8	1.9	1.6	1.5	1.7
TM	Highland^	HLD BK 2		1.0	1.1	1.1	0.8	0.9
TM	Highland^		HLD1	152	153	135	124	146
TM	Highland^		HLD2	97	111	92	96	94
TM	Highland^		HLD3	67	74	78	70	75
TM	Highland^		HLD4	76	78	68	52	61
TM	Holcomb	HOL BK 1		0.0	0.0	0.0	0.0	0.0
TM	Holcomb	HOL BK 2		0.0	0.0	0.0	0.0	0.0
TM	Holcomb	HOL BK 3		0.0	0.0	0.0	0.0	0.0
TM	Holcomb		HOL1	72	74	69	72	1
TM	Holcomb		HOL2	200	232	217	220	229
TM	Holcomb		HOL3	1	1	1	1	1
TM	Holcomb		HOL4	137	200	200	194	212
TM	Holcomb		HOL5	228	192	170	151	174
TM	Holcomb		HOL6	159	201	201	200	194
EAST	Humboldt House	HBH BK 1		0.1	0.1	0.1	0.1	0.0
EAST	Humboldt House		HBH701	11	11	11	11	6
TM	Hunter Lake	HLS BK 1		2.5	2.4	2.4	2.2	2.2
TM	Hunter Lake	HLS BK 2		2.1	2.0	2.0	2.0	2.0
TM	Hunter Lake		HLS1	195	194	193	193	205
TM	Hunter Lake		HLS2	148	143	143	137	153
TM	Hunter Lake		HLS3	288	284	283	296	277
TM	Hunter Lake		HLS4	1	1	1	1	1
EAST	Imlay	ILY BK 1		2.3	2.5	2.4	2.3	2.2
EAST	Imlay		ILY1201	107	117	113	108	102
NTAH	Incline	INC BK 1		29.7	29.2	29.6	29.4	27.9
NTAH	Incline		INC4100	499	480	445	474	397
NTAH	Incline		INC4200	478	474	435	459	413
NTAH	Incline		INC4300	304	304	310	307	317
STAH	Kingsbury	KNG BK 1		0.0	0.0	0.0	0.0	0.0
STAH	Kingsbury		KNG2800	388	388	388	350	410
EAST	Kramer Hill	KRH BK 1		3.5	3.7	3.2	3.7	0.0
EAST	Kramer Hill		KRH1204	153	163	140	162	
EAST	Last Chance	LCH BK 1		43.0	43.2	44.5	39.1	43.3
EAST	Last Chance		LCH211	410	398	387	323	374
EAST	Last Chance		LCH212	198	176	172	134	140
EAST	Last Chance		LCH218	246	252	289	262	284
EAST	Last Chance		LCH221	202	195	197	186	204
EAST	Limerick	LIM BK 1		0.7	0.8	0.7	0.5	0.5
EAST	Limerick		LIM1201	30	35	32	22	21
EAST	Lone Mountain^	LNM BK 1		0.9	1.0	0.7	0.7	0.7
EAST	Lone Mountain^		LNM1201	44	44	35	32	32

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
FF	Lonely	LNY BK 1		23.6	24.0	17.3	21.5	22.8
FF	Lonely		LNY1230	467	464	432	398	411
FF	Lonely		LNY1231	250	254	235	209	223
FF	Lonely		LNY1232	201	206	182	171	206
FF	Lonely		LNY1233	175	187	148	237	244
EAST	Lovelock	LOV BK 1		2.3	2.3	1.9	1.6	1.9
EAST	Lovelock	LOV BK 2		2.0	2.0	1.8	1.7	1.8
EAST	Lovelock	LOV BK 3		0.8	0.8	0.8	0.8	1.0
EAST	Lovelock		LOV1203	35	38	38	38	46
EAST	Lovelock		LOV701	180	181	149	130	153
EAST	Lovelock		LOV702	44	41	37	36	35
EAST	Lovelock		LOV703	118	116	111	97	106
CAR	Lower Smoky Valley	LSV BK 1		0.8	0.8	0.7	0.7	0.7
CAR	Lower Smoky Valley		LSV1260	36	36	34	33	33
CAR	Luning	LUN BK 1		0.0	0.0	0.0	0.0	0.0
CAR	Luning		LUN7005	13	7	3	7	6
CAR	Manhattan	MAN BK 1		0.7	0.7	0.7	0.6	0.4
CAR	Manhattan		MAN1201	34	34	34	28	20
CAR	Mark Twain	MTW BK 1		24.9	25.0	22.6	21.3	21.6
CAR	Mark Twain		MTW218	285	274	248	233	232
CAR	Mark Twain		MTW220	295	304	275	260	269
CAR	Mason Valley	MNV BK 1		14.6	14.3	13.4	13.1	12.4
CAR	Mason Valley	MNV BK 2		11.8	11.8	11.8	7.7	7.9
CAR	Mason Valley		MNV2501	310	286	273	233	239
CAR	Mason Valley		MNV2506	97	97	91	103	103
CAR	Mason Valley		MNV2507	273	273	273	179	183
CAR	Mason Valley		MNV2508	1	1	1	1	1
TM	McCarran	MCN BK 1		4.3	4.5	3.8	3.5	4.2
TM	McCarran		MCN1	400	443	347	373	383
TM	McCarran		MCN2	194	187	175	191	214
EAST	McCoy Mine	MCY BK 1		1.2	1.2	1.2	1.2	1.2
EAST	McCoy Mine		MCY201	28	27	27	27	27
TM	Mill Street	MIL BK 1		2.6	2.6	2.7	2.6	2.8
TM	Mill Street	MIL BK 2		2.2	1.9	1.9	1.9	1.7
TM	Mill Street		MIL1	334	335	334	334	345
TM	Mill Street		MIL2	31	31	47	46	48
TM	Mill Street		MIL3	301	260	260	260	240
CAR	Mina	MNA BK 1		0.4	0.4	0.3	0.3	0.3
CAR	Mina		MNA1202	9	9	7	6	6
CAR	Mina		MNA1203	8	7	6	5	5
CAR	Mina		MNA1204	2	2	2	2	2
CAR	Minden	MIN BK 1		5.4	5.4	4.8	4.7	4.5
CAR	Minden		MIN1271	1	1	1	1	1
CAR	Minden		MIN1272	128	128	117	122	115

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
CAR	Minden		MIN1273	123	122	104	108	92
CAR	Minden		MIN1275	1	1	1	1	1
TM	Mira Loma	MIR BK 3		47.7	46.8	46.7	50.9	54.2
TM	Mira Loma		MIR2502	419	399	406	392	
TM	Mira Loma		MIR2503	246	264	247	403	
TM	Mira Loma		MIR2504	474	485	434	426	
TM	Moana	MOA BK 1		0.1	0.1	0.1	0.1	1.2
TM	Moana	MOA BK 2		1.8	1.9	1.9	1.9	2.2
TM	Moana		MOA2	10	18	18	13	168
TM	Moana		MOA3	256	260	259	259	302
TM	Moana		MOA4	1	1	1	1	1
TM	Mount Rose	MTR BK 1		34.3	35.5	30.4	29.9	32.9
TM	Mount Rose	MTR BK 2		15.7	18.1	17.8	17.7	18.3
TM	Mount Rose		MTR203	219	230	200	179	219
TM	Mount Rose		MTR210	204	215	210	209	134
TM	Mount Rose		MTR242	258	255	253	248	290
TM	Mount Rose		MTR243	246	259	258	255	232
TM	Mount Rose		MTR282	340	365	312	295	315
CAR	Muller	MUR BK 1		19.9	20.0	17.4	16.7	16.9
CAR	Muller		MUR1295	342	336	312	275	287
CAR	Muller		MUR1296	587	589	514	501	512
TM	North Red Rock	NRR BK 1		30.1	29.6	24.6	14.8	
TM	North Red Rock		NRR2503	409	393	270	61	
TM	North Red Rock		NRR2504	288	301	302	299	
EAST	North Valmy	NVY BK 1		0.0	0.0	0.0	0.0	0.0
EAST	North Valmy	NVY BK 2		2.6	3.1	2.7	2.6	2.2
EAST	North Valmy		NVY2401	1	6	4	4	2
EAST	North Valmy		NVY2402	30	41	13	13	3
EAST	North Valmy		NVY2403	34	36	48	48	48
EAST	North Valmy		NVY2404	1	1	1	1	1
TM	Northwest^	NOW BK 1		32.6	32.4	30.5	28.4	31.9
TM	Northwest^	NOW BK 2		41.7	45.0	43.6	39.3	43.2
TM	Northwest^		NOW206	170	161	153	139	148
TM	Northwest^		NOW207	309	291	284	279	329
TM	Northwest^		NOW208	337	350	303	295	319
TM	Northwest^		NOW216	428	451	399	407	425
TM	Northwest^		NOW218	161	141	155	146	176
TM	Northwest^		NOW244	434	402	424	385	358
EAST	Osgood Valley	OSG BK 1		2.2	4.2	7.5	7.4	8.3
EAST	Osgood Valley		OSG201	22	55	134	131	155
EAST	Osgood Valley		OSG202	41	42	43	44	42
CAR	Overland	OVL BK 1		17.7	16.5	11.1	11.2	10.9
CAR	Overland		OVL1250	73	70	66	64	66
CAR	Overland		OVL1260	124	96	1	1	1

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
CAR	Overland		OVL1265	471	442	316	325	323
CAR	Overland		OVL1270	154	154	132	130	116
EAST	Parran	PAR BK 1		0.0	0.0	0.0	0.0	0.0
EAST	Parran		PAR724	3	3	3	3	3
TM	Patrick	PAT BK 1		24.8	25.9	27.2	26.5	28.2
TM	Patrick		PAT224	79	82	81	82	87
TM	Patrick		PAT225	198	272	317	318	89
TM	Patrick		PAT226	291	245	233	245	481
CAR	Pinenut	PNT BK 1		26.6	26.7	23.1	21.7	22.5
CAR	Pinenut		PNT1251	409	410	365	348	348
CAR	Pinenut		PNT1252	1	1	1	1	1
CAR	Pinenut		PNT1253	444	446	415	412	380
CAR	Pinenut		PNT1254	385	386	344	340	340
TM	Pyramid	PYD BK 1		2.5	2.6	2.4	2.3	3.0
TM	Pyramid	PYD BK 2		0.6	0.6	0.6	0.6	0.7
TM	Pyramid		PYD1	220	230	200	230	280
TM	Pyramid		PYD2	134	137	127	116	136
TM	Pyramid		PYD3	72	77	77	77	89
TM	Pyramid		PYD4	15	10	8	8	6
FF	Ray Couch	RYC BK 1		6.6	6.7	6.4	5.9	5.9
FF	Ray Couch	RYC BK 2		6.9	7.1	6.2	3.4	3.7
FF	Ray Couch		RYC1206	136	139	135	123	115
FF	Ray Couch		RYC1207	319	327	289	156	171
FF	Ray Couch		RYC1208	171	173	160	148	160
EAST	Red House	RED BK 1		0.1	0.1	0.1	0.1	0.1
EAST	Red House		RED1401	4	4	4	4	4
EAST	Reese River	RRV BK 1		3.5	3.8	4.4	4.4	4.9
EAST	Reese River		RRV230	71	67	64	59	66
EAST	Reese River		RRV231	27	22	49	49	47
TM	Reno	RNO BK 1		0.6	0.6	0.6	0.7	0.7
TM	Reno	RNO BK 2		1.5	1.3	1.3	2.1	3.0
TM	Reno	RNO BK 3		31.2	30.7	30.7	30.4	30.1
TM	Reno	RNO BK 4		29.7	29.4	31.9	31.6	31.8
TM	Reno		RNO1	80	88	88	103	104
TM	Reno		RNO204	112	104	97	92	99
TM	Reno		RNO216	148	145	143	136	154
TM	Reno		RNO217	1	1	1	5	5
TM	Reno		RNO240	365	367	339	329	300
TM	Reno		RNO243	247	255	221	216	236
TM	Reno		RNO247	215	207	206	205	205
TM	Reno		RNO263	240	235	234	233	250
TM	Reno		RNO285	176	172	176	174	189
TM	Reno		RNO4	95	91	91	90	101
TM	Reno		RNO6	112	96	93	215	312

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
EAST	Rose Creek	RCR BK 1		2.3	2.7	2.7	3.1	2.8
EAST	Rose Creek		RCR201	53	63	62	71	65
STAH	Round Hill	RDH BK 1		18.1	19.2	18.2	20.2	17.1
STAH	Round Hill		RDH1502	243	261	275	285	257
STAH	Round Hill		RDH1503	251	272	263	348	327
STAH	Round Hill		RDH1504	234	235	201	202	193
CAR	Round Mountain	RDM BK 1		17.2	17.3	17.3	17.4	15.5
CAR	Round Mountain	RDM BK 2		16.7	15.9	15.1	15.4	14.9
CAR	Round Mountain		RDM2220	99	98	86	80	65
CAR	Round Mountain		RDM2221	400	400	402	403	360
CAR	Round Mountain		RDM2222	329	309	307	308	280
TM	Rusty Spike	RSK BK 1		30.9	34.2	30.2	27.6	29.1
TM	Rusty Spike		RSK221	63	68	65	61	60
TM	Rusty Spike		RSK254	427	425	420	382	408
TM	Rusty Spike		RSK260	281	302	237	199	206
EAST	Rye Patch	RPH BK 1		0.3	0.4	0.4	0.3	0.4
EAST	Rye Patch		RPH21	71	89	86	76	87
CAR	Sandia	SND BK 1		1.0	1.0	1.0	0.8	0.8
CAR	Sandia		SND1201	47	47	47	36	36
CAR	Santa Fe	SFE BK 1		0.0	0.0	0.0	0.0	0.0
CAR	Santa Fe		SFE1201	1	1	1		
EAST	Setty	STY BK 1		2.9	3.2	2.5	2.3	2.9
EAST	Setty		STY2402	56	63	50	47	55
EAST	Setty		STY251	11	11	8	7	17
TM	Silver Lake	SLK BK 1		11.9	11.6	11.5	9.9	11.2
TM	Silver Lake	SLK BK 2		30.7	30.0	24.8	37.8	36.5
TM	Silver Lake		SLK255	270	269	247	474	485
TM	Silver Lake		SLK256	222	211	198	211	194
TM	Silver Lake		SLK257	274	272	265	230	262
TM	Silver Lake		SLK258	220	215	266	236	167
TM	Silver Lake		SLK259	1	1	1	1	1
CAR	Silver Peak	SVR BK 1		2.5	2.3	2.4	2.2	2.2
CAR	Silver Peak		SVR203	59	54	54	51	50
CAR	Silver Springs	SIL BK 1		7.7	7.5	7.0	6.8	6.8
CAR	Silver Springs		SIL1211	306	307	280	270	275
CAR	Silver Springs		SIL1212	60	58	58	59	60
CAR	Smith Valley	SVL BK 1		17.1	16.0	15.2	12.8	13.1
CAR	Smith Valley		SVL2501	127	115	120	105	101
CAR	Smith Valley		SVL2502	66	66	55	37	51
CAR	Smith Valley		SVL2504	62	64	61	50	51
CAR	Smith Valley		SVL2506	160	150	146	131	126
EAST	Sonoma Heights	SHT BK 1		1.3	1.3	1.2	1.2	1.3
EAST	Sonoma Heights	SHT BK 2		0.4	0.5	0.4	0.4	0.4
EAST	Sonoma Heights	SHT BK 3		0.0	0.0	0.0	0.0	0.0

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Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
EAST	Sonoma Heights		SHT206	1	1	1	1	1
EAST	Sonoma Heights		SHT21	175	189	175	166	175
EAST	Sonoma Heights		SHT23	128	129	123	124	132
EAST	Sonoma Heights		SHT704	34	38	35	32	33
TM	South Meadows	SMD BK 1		27.1	13.3	11.3		
TM	South Meadows		SMD2503	353				
TM	South Meadows		SMD2504	275	309	260		
TM	Spanish Springs	SSP BK 1		50.6	55.4	54.7	53.0	55.0
TM	Spanish Springs	SSP BK 2		55.4	56.5	49.0	53.6	51.8
TM	Spanish Springs		SSP270	427	447	416	388	405
TM	Spanish Springs		SSP271	273	288	260	282	309
TM	Spanish Springs		SSP272	379	407	333	298	328
TM	Spanish Springs		SSP273	479	548	618	558	560
TM	Spanish Springs		SSP274	219	192	262	201	130
TM	Spanish Springs		SSP275	687	710	677	743	741
TM	Sparks Industrial	SID BK 1		8.8	8.9	9.9	8.6	9.4
TM	Sparks Industrial		SID211	1	1	1	1	1
TM	Sparks Industrial		SID229	1	1	1	1	1
TM	Sparks Industrial		SID261	201	204	230	200	215
TM	Sparks Industrial		SID274	1	1	1	1	1
CAR	Stagecoach	STA BK 1		2.5	2.5	2.4	2.2	2.2
CAR	Stagecoach		STA217	57	57	56	52	52
STAH	Stateline	STL BK 1		16.6	16.6	16.9	14.4	16.2
STAH	Stateline	STL BK 3		4.6	4.6	4.6		
STAH	Stateline		STL2001	1	1	1	1	1
STAH	Stateline		STL2200	241	241	252	156	239
STAH	Stateline		STL2300	213	213	213	211	232
STAH	Stateline		STL3101	185	185	185	184	375
STAH	Stateline		STL3501	213	213	213	211	222
TM	Stead	STD BK 1		3.0	3.0	4.5	2.8	12.2
TM	Stead	STD BK 2		3.7	2.0	4.5	3.9	4.3
TM	Stead		STD255	1	1	1	1	1
TM	Stead		STD257	65	68	106	62	286
TM	Stead		STD259	86	47	106	91	100
TM	Steamboat	STM BK 1		46.6	44.9	41.5	39.0	41.3
TM	Steamboat	STM BK 2		24.5	36.9	34.9	36.7	39.2
TM	Steamboat		STM210	310	326	270	258	298
TM	Steamboat		STM212	391	364	360	332	355
TM	Steamboat		STM213	307	312	274	254	272
TM	Steamboat		STM214	194	205	179	220	235
TM	Steamboat		STM215	84	417	400	394	411
TM	Steamboat		STM219	1	1	1	1	1
TM	Steamboat		STM268	394	378	350	317	329
CAR	Stickleman	STK BK 1		0.8	0.8	0.8	0.8	0.7

All values in MVA for transformers
All values in amps for feeders

SIERRA PACIFIC POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
CAR	Stickleman		STK1201	37	38	38	37	32
TM	Sugarloaf	SLF BK 1		42.1	38.6	28.6	49.6	50.3
TM	Sugarloaf	SLF BK 2		33.7	33.1	33.6		
TM	Sugarloaf		SLF2505	227	155			
TM	Sugarloaf		SLF2509	702	689	720	653	
TM	Sugarloaf		SLF2510	95	78	57	66	
TM	Sugarloaf		SLF301	170	139	130	108	107
TM	Sugarloaf		SLF303	576	601	541	386	410
TM	Sutro	SUT BK 1		5.6	4.1	7.4	7.2	8.3
TM	Sutro		SUT211	1	1	1	1	1
TM	Sutro		SUT241	130	96	95	92	107
EAST	T Lazy S	TLS BK 1		1.4	1.3	1.2	0.6	0.6
EAST	T Lazy S		TLS240	33	30	28	13	13
CAR	Topaz	TPZ BK 1		4.0	3.8	3.8	3.5	3.3
CAR	Topaz		TPZ1261	185	177	175	160	154
EAST	Toulon	TLN BK 1		0.1	0.2	0.2	0.1	0.1
EAST	Toulon		TLN701	8	13	18	9	8
TM	Tracy	TCY BK 1		4.1	6.5	6.6	6.2	6.4
TM	Tracy		TCY277	61	79	76	76	76
TM	Tracy		TCY278	35	71	78	77	72
NTAH	Truckee	TRK BK 1		9.7	9.7	9.3	9.3	6.8
NTAH	Truckee		TRK7202	22	23	22	18	22
NTAH	Truckee		TRK7203	323	324	306	260	238
NTAH	Truckee		TRK7204	54	56	52	112	101
TM	University	UNV BK 1		0.7	0.7	0.7	0.7	1.2
TM	University		UNV2	99	94	104	102	134
TM	Valley Road	VAL BK 2		45.0	45.4	43.3	36.2	40.8
TM	Valley Road	VAL BK 3		20.3	20.8	18.8	19.6	18.6
TM	Valley Road		VAL244	10	9	9	10	7
TM	Valley Road		VAL246	201	176	174	176	212
TM	Valley Road		VAL248	317	318	263	297	246
TM	Valley Road		VAL249	362	369	375	352	376
TM	Valley Road		VAL251	151	157	165	170	179
TM	Valley Road		VAL254	62	61	59	57	41
TM	Valley Road		VAL262	419	447	396	361	397
TM	Verdi PH	VRD BK 1		0.0	0.0	0.0	0.0	0.0
TM	Verdi PH		VRD204	1	1	1	1	1
CAR	Virginia City	VCY BK 1		2.8	2.9	2.7	2.7	2.8
CAR	Virginia City		VCY213	4	4	4	4	10
CAR	Virginia City		VCY214	28	28	27	27	26
CAR	Virginia City		VCY215	34	34	31	35	29
FF	Wadsworth	WAD BK 1		2.9	2.9	2.5	2.4	2.4
FF	Wadsworth		WAD1220	16	1	1		
FF	Wadsworth		WAD1221	121	134	117	110	110

All values in MVA for transformers
All values in amps for feeders

SIERRA PACIFIC POWER COMPANY 2018-2022
SUBSTATION TRANSFORMER AND FEEDER PAST PEAKS

Region	Substation	Transformer	Feeder	2022	2021	2020	2019	2018
TM	Washoe PH	WSO BK 1		1.3	1.3	1.5	2.4	2.5
TM	Washoe PH		WSO201	29	29	33	57	56
TM	Washoe PH		WSO203	1	1	1	1	1
TM	Washoe PH		WSO204	1	1	1	1	1
TM	West 7th Street	WST BK 1		3.4	4.1	4.1	3.3	3.8
TM	West 7th Street		WST1	230	364	364	398	305
TM	West 7th Street		WST2	216	183	183	182	194
CAR	West Tonopah	WTP BK 1		6.0	6.0	6.1	6.0	4.5
CAR	West Tonopah		WTP1201	120	130	132	137	84
CAR	West Tonopah		WTP1202	68	69	70	52	47
CAR	West Tonopah		WTP1203	90	79	78	89	78
FF	Westside^	WES BK 1		9.7	9.6	9.2	7.2	7.6
FF	Westside^		WES1211	229	212	206	180	195
FF	Westside^		WES1212	135	126	110	97	104
FF	Westside^		WES1213	86	108	112	67	63
TM	Wheeler	WLR BK 2		1.4	1.3	1.3	1.2	1.5
TM	Wheeler		WLR2	190	178	175	163	204
EAST	Winnemucca	WIN BK 2		22.5	23.4	21.2	19.8	19.5
EAST	Winnemucca	WIN BK 3		0.5	0.5	0.5		
EAST	Winnemucca		WIN201	220	226	212	186	189
EAST	Winnemucca		WIN202	1	1	1	1	1
EAST	Winnemucca		WIN205	166	177	155	131	142
EAST	Winnemucca		WIN206	135	138	123	111	118
EAST	Winnemucca		WIN701	40	40	38	38	1

All values in MVA for transformers
All values in amps for feeders

DRP UPDATE-3

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
2023-2029 SUBSTATION TRANSFORMER PEAK FORECAST

Company	Region	Substation	Transformer	Rating (MVA)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	NE	Allen	ALN BK 1//2	74	62.2	63.9	65.5	66.4	67.4	68.3	69.2
Nevada Power	NE	Allen	ALN BK 3	37	22.4	23.6	23.8	24.1	24.5	24.9	25.3
Nevada Power	NE	Alta	AL BK 3	37.3	24.8	25.2	25.6	26.2	26.7	27.2	27.7
Nevada Power	NE	Alta	AL BK 4	22.4	13.1	13.2	13.3	13.5	13.6	13.7	13.9
Nevada Power	NE	Alta	AL BK 5	37.3	28.9	29.7	30.1	30.3	30.7	31.2	31.6
Nevada Power	NE	Alta	AL BK 6	22.4	5.5	5.5	5.5	5.6	5.6	5.7	5.7
Nevada Power	NE	Andrews	AND BK 1//2	74	52.5	59.2	70.4	71.1	71.8	76.7	81.5
Nevada Power	NW	Angel Peak	AP BK 1	4.83	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Nevada Power	NW	Angel Peak	AP BK 2	5	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Nevada Power	SE	Anthem	ANT BK 1//2	74.6	60.6	61.3	62.2	63.1	64.3	65.2	66.1
Nevada Power	SE	Anthem	ANT BK 3	37	8.3	8.4	8.5	8.7	8.8	9.0	9.1
Nevada Power	SW	Arden	AD BK 4//5	74	60.0	65.4	71.7	76.1	79.7	84.7	89.6
Nevada Power	NE	Artesian	AR BK 2	37.3	28.4	29.3	33.3	33.5	33.9	35.2	36.6
Nevada Power	NE	Artesian	AR BK 3//4	74.6	56.6	59.0	60.6	61.0	61.6	62.9	64.1
Nevada Power	SW	Avera	AVR BK 1	56	47.8	51.1	55.8	57.9	59.5	62.4	65.4
Nevada Power	SW	Avera	AVR BK 2	56	33.8	36.7	41.4	45.7	49.7	53.7	57.7
Nevada Power	SE	Balboa	BL BK 1	22.4	18.4	18.8	19.3	20.0	20.7	21.2	21.8
Nevada Power	SE	Balboa	BL BK 2//3	44.8	31.6	33.4	35.3	36.8	38.0	39.6	41.3
Nevada Power	NW	Beltway	BLT BK 3//4	74	46.6	50.1	52.9	55.7	58.3	61.3	64.2
Nevada Power	SE	Bicentennial	BCT BK 1//2	74	72.9	76.6	80.7	85.0	88.8	92.8	96.8
Nevada Power	SE	Big Bend	BGB BK 1	22.4	5.1	5.6	5.6	5.6	5.7	5.8	6.0
Nevada Power	SE	Big Bend	BGB BK 2	22.4	10.9	10.9	11.0	11.0	11.2	11.2	11.3
Nevada Power	NE	Blade Runner	BLR BK 1	28	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Nevada Power	SW	Blue Diamond	BD BK 2//3	5	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nevada Power	SE	Boulder Beach	BB BK 1	9.3	1.9	2.3	3.5	3.5	3.6	4.0	4.4
Nevada Power	SE	Burnham	BRN BK 1//2	74.6	50.7	52.1	53.8	54.7	55.6	56.8	58.0
Nevada Power	SE	Burnham	BRN BK 3	37.3	23.3	23.6	24.2	24.4	24.7	25.0	25.3
Nevada Power	SE	Cabana	CB BK 1//2	74.6	57.1	57.5	58.5	59.6	60.8	61.7	62.6
Nevada Power	SE	Cabana	CB BK 3	37	22.8	22.8	22.9	23.1	23.3	23.5	23.6
Nevada Power	SE	Cactus	CCT BK 1//2	74	39.7	42.9	46.8	49.1	50.5	53.3	56.0
Nevada Power	SW	Camero	CMO BK 2	37	18.2	19.6	29.7	30.6	31.0	34.2	37.4
Nevada Power	NW	Canyon	CN BK 1	5	1.7	1.7	1.7	1.7	1.7	1.7	1.8
Nevada Power	NE	Carey	CA BK 5	22.4	8.3	10.6	11.2	11.3	11.4	12.1	12.9
Nevada Power	NE	Carey	CA BK 6//7	44.8	31.8	33.6	37.0	38.0	38.8	40.5	42.3
Nevada Power	NE	Carey	CA BK 8//9	44.8	16.2	16.4	16.5	16.6	16.8	16.9	17.1
Nevada Power	NW	Charleston	CHR BK 1	28	13.2	13.3	13.4	13.6	13.7	13.9	14.0
Nevada Power	NW	Cheyenne	CHN BK 1//2	74.6	53.2	53.4	53.9	54.4	55.2	55.7	56.2
Nevada Power	NW	Cheyenne	CHN BK 3	37.3	19.7	19.8	20.0	20.2	20.5	20.7	20.9
Nevada Power	STRIP	Claymont	CM BK 1	37.3	21.5	21.5	21.6	21.8	22.0	22.2	22.3
Nevada Power	STRIP	Claymont	CM BK 2	37.3	23.7	24.2	24.6	24.8	25.0	25.3	25.7
Nevada Power	STRIP	Claymont	CM BK 3	37.3	20.0	20.2	23.0	23.2	23.4	24.3	25.1
Nevada Power	STRIP	Claymont	CM BK 4	37.3	24.6	26.5	26.6	26.8	27.1	27.7	28.3
Nevada Power	NW	Cold Creek	CC BK 2	22.4	5.1	5.1	5.1	5.2	5.2	5.2	5.3
Nevada Power	STRIP	Commerce	COM BK 1	56	10.6	12.5	13.8	14.4	14.6	15.6	16.5
Nevada Power	STRIP	Commerce	COM BK 2	56	22.9	24.4	26.3	27.5	27.7	28.9	30.1
Nevada Power	STRIP	Concourse	CON BK 1	37.3	19.3	22.4	26.5	26.7	27.0	28.9	30.8
Nevada Power	STRIP	Concourse	CON BK 2//3	74.6	41.7	42.6	43.5	47.2	54.5	57.6	60.8
Nevada Power	NE	Craig	CR BK 1//2	74.6	56.6	59.4	62.2	62.8	63.5	65.3	67.0
Nevada Power	NE	Craig	CR BK 3	37	27.5	29.1	29.3	29.6	29.9	30.5	31.1
Nevada Power	NE	DeBuono	DEB BK 1	22.4	15.2	15.3	15.4	15.5	15.7	15.8	16.0
Nevada Power	NE	DeBuono	DEB BK 2//3	44.8	32.5	32.6	32.8	33.1	33.5	33.8	34.0
Nevada Power	SW	Decatur	DE BK 3//7	44.8	34.2	34.4	34.7	34.9	35.3	35.5	35.8
Nevada Power	SW	Decatur	DE BK 4//5	44.8	26.2	32.3	36.6	36.9	37.3	40.1	42.9
Nevada Power	SW	Durango	DU BK 1	37.3	21.5	21.9	22.4	22.6	22.8	23.2	23.5
Nevada Power	SW	Durango	DU BK 2//3	74.6	50.4	51.3	52.0	52.7	53.6	54.4	55.2
Nevada Power	NW	El Capitan	ELC BK 1	56	39.0	42.5	43.1	43.8	44.9	46.4	47.8
Nevada Power	NW	El Capitan	ELC BK 2	56	46.4	50.5	52.4	53.3	54.3	56.2	58.2
Nevada Power	STRIP	El Rancho	ER BK 1	17.5	10.7	11.0	11.3	11.3	11.5	11.6	11.8
Nevada Power	STRIP	El Rancho	ER BK 2//3	35	19.2	22.0	22.1	22.3	22.5	23.3	24.2
Nevada Power	NW	Elkhorn	ELK BK 1//2	74	64.7	65.8	68.5	70.4	72.0	73.8	75.6

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
2023-2029 SUBSTATION TRANSFORMER PEAK FORECAST

Company	Region	Substation	Transformer	Rating (MVA)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	NW	Elkhorn	ELK BK 3//4	74	38.5	42.6	47.4	48.9	50.5	53.5	56.5
Nevada Power	STRIP	Excalibur	EX BK 1//2	44.8	30.0	30.0	30.2	30.4	30.7	30.8	31.0
Nevada Power	STRIP	Excalibur	EX BK 3//4	44.8	23.5	23.5	23.7	23.8	24.1	24.2	24.3
Nevada Power	SE	Faulkner	FLK BK 3	56	37.0	39.3	44.2	45.2	46.1	48.4	50.7
Nevada Power	SE	Faulkner	FLK BK 4	56	39.6	44.7	48.6	49.5	50.5	53.2	55.9
Nevada Power	SE	Faulkner	FLK BK 5	56	21.7	23.9	26.4	28.7	30.9	33.2	35.5
Nevada Power	STRIP	Flamingo	FL BK 1	22.4	9.7	9.7	9.8	9.8	9.9	10.0	10.1
Nevada Power	STRIP	Flamingo	FL BK 2//3	44.8	22.4	28.6	34.4	34.6	35.0	38.1	41.3
Nevada Power	SE	Ford	FRD BK 1	56	27.1	27.7	28.0	28.4	28.8	29.2	29.6
Nevada Power	SE	Ford	FRD BK 2	56	39.9	41.5	44.8	46.0	46.9	48.6	50.3
Nevada Power	SW	Frias	FRS BK 1//2	74	39.4	40.5	42.1	44.0	46.0	47.6	49.3
Nevada Power	SW	Frias	FRS BK 3	37	30.1	31.1	31.6	32.3	32.9	33.6	34.4
Nevada Power	STRIP	Garces	GA BK 2//3	44.8	26.9	28.8	31.1	32.1	32.4	33.7	35.1
Nevada Power	STRIP	Garces	GA BK 4	22.4	7.0	8.6	8.8	8.8	8.9	9.4	9.9
Nevada Power	NE	Gilmore	GLM BK 1//2	74	49.4	53.8	55.4	55.8	56.5	58.2	60.0
Nevada Power	SW	Goodsprings	GS BK 1	3.1	0.8	0.9	0.9	0.9	0.9	0.9	0.9
Nevada Power	NE	Grand Teton	GTT BK 2	37	24.5	26.6	30.3	33.7	36.9	40.0	43.2
Nevada Power	SE	Green Valley	GV BK 1	37.3	29.8	31.2	31.5	31.8	32.2	32.8	33.4
Nevada Power	SE	Green Valley	GV BK 2//3	74.6	52.2	53.1	54.1	55.0	55.8	56.8	57.7
Nevada Power	SE	Greenway	GNW BK 1//2	74	33.9	34.6	35.2	35.7	36.4	37.0	37.6
Nevada Power	NE	Gypsum	GYP BK 2	22.4	11.3	25.4	36.3	44.6	45.4	53.9	62.4
Nevada Power	SE	Haven	HV BK 1	37	28.2	29.2	31.2	32.3	32.7	33.9	35.0
Nevada Power	SE	Haven	HV BK 2//3	74.6	46.0	53.7	59.1	61.2	62.1	66.1	70.1
Nevada Power	STRIP	Highland	HI BK 1//2	44.8	25.7	27.4	27.7	27.9	28.2	28.9	29.5
Nevada Power	STRIP	Highland	HI BK 3	22.4	9.2	11.4	12.3	12.4	12.5	13.4	14.2
Nevada Power	STRIP	Highland	HI BK 4//5	74.6	26.6	28.3	32.8	35.1	35.9	38.3	40.6
Nevada Power	STRIP	Highland	HI BK 6	37	12.2	13.8	15.5	17.3	17.9	19.3	20.7
Nevada Power	STRIP	Highland	HI BK 8	56	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Nevada Power	NW	Hualapai	HU BK 1//2	74.6	53.5	53.9	54.6	55.3	56.2	56.9	57.6
Nevada Power	NW	Hualapai	HU BK 3	37	19.5	22.2	23.0	23.3	23.7	24.7	25.8
Nevada Power	NW	Indian Springs	IS BK 1	7	2.3	2.6	2.7	2.9	3.0	3.2	3.4
Nevada Power	NW	Indian Springs	IS BK 2	11.2	5.9	6.0	6.0	6.1	6.1	6.2	6.2
Nevada Power	NW	Iron Mountain	IMT BK 1//2	74	56.2	56.7	57.4	58.3	59.3	60.1	60.9
Nevada Power	SW	Jean	JN BK 2	15.6	9.6	9.7	12.7	14.0	14.1	15.3	16.4
Nevada Power	SE	Keehn	KHN BK 1//2	74	43.1	51.0	60.1	66.0	69.7	76.3	82.9
Nevada Power	SE	Kidwell	KI BK 1	3.5	1.0	1.2	1.2	1.2	1.2	1.3	1.4
Nevada Power	NW	Kyle Canyon	KC BK 1	5.25	1.1	1.3	1.3	1.3	1.4	1.4	1.5
Nevada Power	SE	Lake Las Vegas	LLV BK 1//2	44.8	23.1	25.8	29.2	32.1	34.8	37.7	40.6
Nevada Power	SE	Larson	LRS BK 2	37.3	4.3	15.5	25.1	32.9	38.6	47.2	55.7
Nevada Power	NE	Leavitt	LVT BK 1	37	29.4	32.1	34.3	34.7	35.3	36.7	38.2
Nevada Power	NE	Leavitt	LVT BK 2//3	74	54.0	55.4	61.0	61.7	62.5	64.6	66.7
Nevada Power	STRIP	Lewis	LE BK 2	22.4	1.1	1.1	1.1	1.2	1.2	1.2	1.2
Nevada Power	NE	Lincoln	LCN BK 1//2	74	52.1	58.2	63.6	64.2	64.9	68.1	71.3
Nevada Power	SW	Lindell	LI BK 1//2	44.8	29.2	29.9	30.4	30.8	31.3	31.9	32.4
Nevada Power	SW	Lindell	LI BK 3	22.4	14.6	15.0	15.2	15.3	15.5	15.7	15.9
Nevada Power	SE	Lindquist	LDQ BK 1//2	44.8	37.8	40.6	45.9	48.4	50.6	53.8	56.9
Nevada Power	NW	Lone Mountain	LMT BK 1//2	74	34.6	35.7	36.6	37.3	38.2	39.0	39.9
Nevada Power	NW	Lorenzi	LO BK 1//2	74.6	65.8	68.3	69.4	70.3	71.3	72.7	74.0
Nevada Power	NW	Lorenzi	LO BK 3	37.3	25.0	25.3	25.9	26.6	27.2	27.8	28.3
Nevada Power	STRIP	Lynnwood	LY BK 1//2	44.8	28.9	30.6	31.4	31.6	32.0	32.7	33.5
Nevada Power	SE	Magic Way	MAG BK 1	25	19.7	20.0	20.2	20.4	20.7	21.0	21.2
Nevada Power	STRIP	Mayfair	MA BK 1	6.25	2.9	2.9	2.9	3.0	3.0	3.0	3.1
Nevada Power	STRIP	Mayfair	MA BK 2	22.4	13.4	13.5	13.6	13.7	13.9	14.0	14.1
Nevada Power	STRIP	Mayfair	MA BK 3//4	44.8	31.3	32.4	32.7	36.6	37.0	38.4	39.9
Nevada Power	SW	McDonald	MCD BK 3	56	28.3	32.2	43.7	45.1	45.7	50.1	54.4
Nevada Power	SW	McDonald	MCD BK 4	56	36.5	49.1	50.7	52.0	53.6	57.9	62.1
Nevada Power	STRIP	MGM	MGM BK 4	22.4	5.8	10.3	19.1	19.2	19.4	22.8	26.2
Nevada Power	NW	Michael Way	MW BK 1//2	44.8	37.1	37.6	38.1	38.6	39.2	39.8	40.3
Nevada Power	NW	Michael Way	MW BK 3	22.4	15.0	16.2	18.7	19.6	19.9	21.1	22.3
Nevada Power	NE	Miller	MI BK 3//4	44.8	34.8	38.7	40.4	40.8	41.2	42.8	44.4

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Company	Region	Substation	Transformer	Rating (MVA)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Mission	MS BK 1//4	44.8	25.2	25.8	29.5	36.6	38.1	41.4	44.6
Nevada Power	SE	Mission	MS BK 2//3	44.8	37.6	39.9	43.2	45.1	46.9	49.2	51.5
Nevada Power	SW	Mountains Edge	MTE BK 2//3	74	67.9	69.9	72.3	74.4	76.6	78.8	80.9
Nevada Power	SW	MYS	MYS BK 2//3	74	60.8	65.7	70.9	75.4	77.6	81.9	86.1
Nevada Power	SE	National Park Service	NPS BK 1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nevada Power	NE	Nellis	NS BK 1//2	25	19.6	22.4	24.3	24.6	24.9	26.2	27.5
Nevada Power	NE	Nellis	NS BK 3	22.4	8.4	14.5	20.0	20.2	20.4	23.4	26.4
Nevada Power	SE	Nelson	NL BK 1	1.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nevada Power	NE	North Las Vegas	NLV BK 1	22.4	18.2	18.3	18.4	18.6	18.8	18.9	19.1
Nevada Power	NE	North Las Vegas	NLV BK 3//4	44.8	29.2	35.6	38.8	39.1	39.5	42.1	44.6
Nevada Power	NW	Northwest	NW BK 4	56	30.4	33.6	36.3	38.9	41.6	44.4	47.1
Nevada Power	NW	Northwest	NW BK 5	56	40.5	42.3	45.4	47.1	49.0	51.2	53.3
Nevada Power	SW	Oasis	OA BK 1	14	5.3	5.3	5.3	5.4	5.4	5.4	5.5
Nevada Power	SW	Oasis	OA BK 2//3	28	7.0	8.0	9.7	14.4	14.9	16.9	18.9
Nevada Power	NE	Olive	OL BK 1	22.4	16.9	17.1	17.2	17.4	17.6	17.8	18.0
Nevada Power	STRIP	Oquendo	OQ BK 1	22.4	18.3	19.2	19.2	19.4	19.6	19.9	20.2
Nevada Power	STRIP	Oquendo	OQ BK 2//3	44.8	26.2	34.6	39.6	39.9	40.3	43.8	47.3
Nevada Power	NE	Pabco	PBC BK 2	14	11.7	11.9	12.0	12.0	12.2	12.3	12.4
Nevada Power	STRIP	Pawnee	PA BK 1//2	44.8	33.4	35.0	35.4	35.7	36.1	36.7	37.4
Nevada Power	SW	Peace	PCE BK 1//2	74	37.2	38.7	41.2	43.2	45.3	47.3	49.3
Nevada Power	SW	Peace	PCE BK 3	37.3	26.7	27.6	28.7	29.5	29.9	30.7	31.5
Nevada Power	SE	Pearl	PL BK 1	22.4	17.3	17.3	17.5	17.7	18.0	18.1	18.3
Nevada Power	SE	Pearl	PL BK 2//3	44.8	36.5	37.1	37.7	38.2	38.8	39.3	39.9
Nevada Power	SE	Pebble	PB BK 1//2	74.6	51.0	51.5	56.3	57.0	57.9	59.6	61.3
Nevada Power	SE	Pebble	PB BK 3	37.3	29.3	30.2	31.8	32.4	32.9	33.9	34.8
Nevada Power	NE	Pecos	PE BK 6//7	74	44.4	52.0	54.9	56.3	57.3	60.5	63.7
Nevada Power	STRIP	Polaris	POL BK 1//2	74.6	32.6	37.1	40.5	40.8	41.2	43.3	45.4
Nevada Power	STRIP	Polaris	POL BK 3	37	20.5	21.6	22.7	22.9	23.1	23.8	24.5
Nevada Power	NE	Prince	PR BK 1//2	44.8	33.1	33.2	33.4	33.7	34.0	34.2	34.5
Nevada Power	STRIP	Procyon	PRO BK 2	37	17.6	17.6	17.7	17.9	18.0	18.1	18.2
Nevada Power	STRIP	Procyon	PRO BK 3	37	6.0	6.0	6.0	6.1	6.1	6.2	6.2
Nevada Power	NE	Prospector	PRS BK 2//3	74.6	1.7	21.5	56.6	58.3	58.9	73.2	87.5
Nevada Power	SW	Quail	QUL BK 1	37.3	21.2	22.7	26.9	30.0	31.9	34.6	37.3
Nevada Power	SW	Quail	QUL BK 2//3	74.3	51.4	54.3	61.1	65.7	68.0	72.2	76.3
Nevada Power	NW	Radar	RA BK 1	2.8	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nevada Power	SW	Railroad	RLR BK 1//2	74	59.4	61.4	62.6	63.9	65.4	66.9	68.4
Nevada Power	SW	Railroad	RLR BK 3	37	16.7	16.7	16.8	16.9	17.0	17.1	17.2
Nevada Power	NW	Rainbow	RB BK 1//2	44.8	37.1	37.4	37.9	38.5	39.3	39.8	40.3
Nevada Power	NW	Rainbow	RB BK 3	22.4	18.9	18.9	19.1	19.3	19.6	19.7	19.9
Nevada Power	SE	Ranger	RN BK 1	9.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Nevada Power	SW	Red Rock	RRK BK 1//2	74	47.2	48.4	51.1	53.5	54.4	56.2	58.1
Nevada Power	NW	Regena	RGN BK 2	37	30.9	31.6	32.6	33.1	33.6	34.3	35.0
Nevada Power	SW	Riley	RLY BK 2//3	74	57.8	59.3	61.3	63.1	64.8	66.6	68.4
Nevada Power	SE	River Road	RI BK 1	22.4	13.6	13.7	13.9	14.0	14.1	14.3	14.4
Nevada Power	SE	River Road	RI BK 2	10.5	4.4	4.5	4.5	4.5	4.6	4.6	4.6
Nevada Power	SW	Robindale	ROB BK 1	37	21.9	25.0	28.6	30.8	31.4	33.7	36.1
Nevada Power	SW	Robindale	ROB BK 2//3	74	63.4	67.0	72.4	76.5	78.9	82.7	86.6
Nevada Power	SW	Rosanna	RO BK 1//2	44.8	34.8	35.5	36.2	36.8	37.4	38.0	38.7
Nevada Power	SW	Rosanna	RO BK 3	22.4	15.0	16.5	18.2	18.6	18.9	19.9	20.8
Nevada Power	SE	Russell	RS BK 1//2	74.6	52.5	53.4	54.1	54.6	55.2	55.9	56.6
Nevada Power	SE	Russell	RS BK 3	37.3	23.2	23.9	24.6	25.4	26.1	26.8	27.6
Nevada Power	SE	Sahara	SA BK 1//4	44.8	28.6	28.6	28.8	29.1	29.4	29.6	29.8
Nevada Power	SE	Sahara	SA BK 2//3	44.8	33.5	34.4	35.7	36.0	36.4	37.2	37.9
Nevada Power	STRIP	San Francisco	SF BK 1//2	35	27.7	27.8	28.4	28.7	29.0	29.3	29.7
Nevada Power	STRIP	San Francisco	SF BK 3//4	35	27.4	27.8	29.2	29.4	29.7	30.3	30.9
Nevada Power	SE	Searchlight	SE BK 1	9.3	2.8	3.0	3.0	3.0	3.1	3.1	3.2
Nevada Power	NE	Shadow	SH BK 3	6.6	3.2	3.4	3.4	3.4	3.4	3.5	3.6
Nevada Power	NE	Shadow	SH BK 4//5	44.8	29.9	30.2	32.2	32.9	33.3	34.1	34.9
Nevada Power	NW	Silver Flag	SLV BK 1	11.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nevada Power	STRIP	Sinatra	SNT BK 1	56	7.2	7.2	7.2	7.3	7.3	7.4	7.4

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Nevada Power	STRIP	Sinatra	SNT BK 2	56	14.8	14.8	14.9	15.0	15.1	15.2	15.3
Nevada Power	NW	Skelton	SKL BK 1	56	46.4	46.8	47.5	48.2	49.0	49.6	50.2
Nevada Power	NW	Skelton	SKL BK 2	56	37.2	38.5	39.5	40.4	41.4	42.4	43.4
Nevada Power	NW	Snow Mountain	SN BK 1	18.6	2.0	3.5	4.4	4.4	4.5	5.1	5.7
Nevada Power	SE	Southpoint	SO BK 1	22.4	6.2	6.2	6.2	6.2	6.3	6.3	6.4
Nevada Power	SE	Southpoint	SO BK 2	22.4	6.1	7.3	7.4	7.4	7.5	7.8	8.2
Nevada Power	SW	Sparta	SPA BK 2//3	74	53.4	56.8	60.3	64.0	66.2	69.4	72.6
Nevada Power	NE	Speedway	SPD BK 1//2	74	60.7	82.3	88.1	88.9	89.8	97.0	104.3
Nevada Power	STRIP	Spencer	SP BK 3//4	44.8	25.2	25.9	229	32.3	39.5	41.5	42.1
Nevada Power	STRIP	Spencer	SP BK 5	22.4	17.2	17.3	19.3	19.5	19.7	19.9	20.1
Nevada Power	SW	Spring Mountain	SM BK 1	9.3	4.8	4.8	5.0	5.1	5.1	5.2	5.3
Nevada Power	SW	Spring Valley	SV BK 1//4	44.8	22.1	23.0	23.9	24.1	24.4	25.0	25.6
Nevada Power	SW	Spring Valley	SV BK 2//3	44.8	39.5	39.6	39.9	40.2	40.7	41.0	41.3
Nevada Power	STRIP	Strip	STR BK 1	56	24.3	24.7	25.5	25.6	25.9	26.3	26.7
Nevada Power	STRIP	Strip	STR BK 2	56	22.6	22.6	22.7	22.8	23.1	23.2	23.3
Nevada Power	NW	Summerlin	SMR BK 1	56	39.5	40.1	40.8	41.3	42.0	42.6	43.2
Nevada Power	NW	Summerlin	SMR BK 2	56	36.6	36.8	37.2	37.6	38.2	38.6	39.0
Nevada Power	SE	Sunset	SUS BK 1//2	44.8	30.7	35.4	43.2	48.7	53.8	59.6	65.4
Nevada Power	STRIP	Suzanne	SZ BK 1//2	74.6	49.1	55.0	58.6	59.1	59.8	62.5	65.2
Nevada Power	STRIP	Suzanne	SZ BK 3	37	21.4	24.8	25.0	25.1	25.4	26.4	27.4
Nevada Power	STRIP	Swenson	SWN BK 1//2	74	33.3	36.3	36.5	36.8	37.2	38.2	39.2
Nevada Power	STRIP	Swenson	SWN BK 3	37.3	26.2	28.2	28.3	28.5	28.8	29.5	30.1
Nevada Power	SW	Tam	TA BK 1	22.4	15.9	16.0	16.1	16.3	16.6	16.7	16.9
Nevada Power	SW	Tam	TA BK 2//3	44.8	32.8	33.2	33.4	33.6	34.0	34.3	34.6
Nevada Power	NW	Tenaya	TE BK 1	37.3	19.4	19.5	19.6	19.8	20.0	20.2	20.3
Nevada Power	NW	Tenaya	TE BK 2//3	74.6	56.2	56.6	57.4	57.8	58.5	59.0	59.6
Nevada Power	SE	Tolson	TOL BK 3	56	46.0	47.8	50.6	52.7	54.1	56.1	58.1
Nevada Power	SE	Tolson	TOL BK 4	56	47.4	48.2	49.3	50.1	50.8	51.7	52.5
Nevada Power	SW	Tomsik	TOM BK 2//3	74	64.1	75.9	83.5	88.9	92.5	99.6	106.6
Nevada Power	NE	Tonopah	TO BK 1//2	44.8	38.6	41.1	42.9	43.6	44.2	45.6	47.0
Nevada Power	NE	Tonopah	TO BK 3	22.4	13.9	14.6	14.8	15.0	15.2	15.5	15.9
Nevada Power	NE	Tropical	TRO BK 1//2	74	58.3	61.7	63.8	65.2	66.8	68.9	71.0
Nevada Power	NE	Tropical	TRO BK 3	37	31.8	33.4	33.6	34.0	34.4	35.0	35.7
Nevada Power	STRIP	Truman	TR BK 1//2	28	11.8	13.3	16.5	17.8	18.0	19.5	21.1
Nevada Power	STRIP	Valley View	VV BK 1	22.4	11.2	14.7	17.3	17.4	17.6	19.2	20.8
Nevada Power	STRIP	Valley View	VV BK 2//3	44.8	28.5	31.8	34.2	34.5	34.8	36.4	38.0
Nevada Power	NW	Vegas	VGS BK 1//2	74.6	52.3	52.6	53.2	53.9	54.7	55.3	55.9
Nevada Power	NW	Vegas	VGS BK 3	37	23.9	24.6	24.9	25.2	25.5	25.9	26.3
Nevada Power	NW	Village	VLG BK 1	37	31.9	32.4	33.0	33.6	34.3	35.0	35.6
Nevada Power	SE	Warmsprings	WSP BK 1//2	74.6	51.3	52.4	54.2	55.8	56.7	58.0	59.3
Nevada Power	SE	Warmsprings	WSP BK 3	37.3	27.8	28.4	29.0	29.3	29.7	30.2	30.7
Nevada Power	NE	Washburn	WSH BK 1	37.3	27.1	27.3	27.8	28.1	28.6	28.9	29.3
Nevada Power	NE	Washburn	WSH BK 2//3	74.3	65.0	66.2	67.3	68.5	69.9	71.1	72.3
Nevada Power	NE	Washington	WN BK 1//2	44.8	35.7	35.9	36.1	36.4	36.8	37.0	37.3
Nevada Power	NE	Washington	WN BK 3//4	44.8	35.7	36.7	36.9	37.2	37.6	38.1	38.5
Nevada Power	SE	Water Street	WA BK 1//2	44.8	32.3	34.9	37.5	39.2	40.6	42.7	44.8
Nevada Power	SE	Water Street	WA BK 3	22.4	8.6	10.2	11.1	11.7	12.3	13.2	14.1
Nevada Power	NW	Westside	WE BK 3	37	11.0	11.5	11.6	11.7	11.9	12.1	12.3
Nevada Power	NW	Westside	WE BK 5	37.3	19.3	19.3	19.5	19.6	19.9	20.0	20.2
Nevada Power	NW	Westside	WE BK 6//7	74.6	56.7	57.0	57.6	59.7	60.5	61.5	62.5
Nevada Power	SE	Whitney	WH BK 1//2	35	28.8	29.3	30.5	31.1	31.8	32.5	33.2
Nevada Power	SE	Whitney	WH BK 3//4	35	28.3	29.4	30.9	31.5	32.0	33.0	33.9
Nevada Power	SE	Wigwam	WI BK 1//2	74.6	56.8	57.3	57.9	58.7	59.6	60.3	61.0
Nevada Power	SE	Wigwam	WI BK 3	37.3	26.9	28.5	29.1	29.6	30.1	30.9	31.7
Nevada Power	SE	Wilson	WIL BK 1	56	36.6	38.4	39.2	39.9	40.7	41.7	42.7
Nevada Power	SE	Wilson	WIL BK 2	56	42.5	43.9	44.6	45.2	45.9	46.8	47.6
Nevada Power	SE	Winterwood	WW BK 1//2	44.8	36.7	37.8	38.3	38.6	39.0	39.6	40.1
Nevada Power	SE	Winterwood	WW BK 3	22.4	12.6	12.7	12.8	12.9	13.0	13.1	13.2
Nevada Power	SE	Winterwood	WW BK 7//8	44.8	40.3	40.6	40.9	41.2	41.7	42.1	42.4
Sierra	EAST	Adobe	ADB BK 1	33.6	14.9	15.1	15.3	15.5	15.6	15.8	16.0

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Sierra	EAST	Adobe	ADB BK 2	33.6	13.8	13.9	14.1	14.3	14.6	14.8	15.0
Sierra	TM	Airport	AIR BK 2	5.25	3.0	3.0	3.0	3.0	3.1	3.1	3.1
Sierra	TM	Airport	AIR BK 3	46.7	32.5	34.0	35.8	36.5	37.2	38.4	39.5
Sierra	TM	Airport	AIR BK 4	60	32.6	35.1	36.8	37.3	37.8	39.1	40.4
Sierra	EAST	Antelope Valley	ANV BK 1	14	6.3	6.3	6.3	6.4	6.5	6.5	6.5
Sierra	EAST	Antelope Valley	ANV BK 2	10.5	5.8	5.8	5.9	5.9	6.0	6.0	6.0
Sierra	FF	Austin	AST BK 1	25	4.7	5.2	5.2	5.2	5.3	5.5	5.6
Sierra	EAST	Battle Mountain	BMT BK 2	7	6.3	6.3	6.3	6.4	6.5	6.5	6.5
Sierra	EAST	Battle Mountain	BMT BK 3	4.687	4.0	4.0	4.0	4.1	4.1	4.1	4.2
Sierra	TM	Bella Vista	BLV BK 1	33.6	23.2	23.2	23.4	23.6	23.9	24.0	24.2
Sierra	TM	Bella Vista	BLV BK 2	60	45.1	46.9	47.5	48.1	49.0	49.9	50.9
Sierra	EAST	Big Springs	BSP BK 1	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	FF	Brady's	BDY BK 1	5	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Sierra	CAR	Brunswick	BWK BK 3	28	8.4	8.5	8.5	8.6	8.7	8.7	8.8
Sierra	CAR	Brunswick	BWK BK 4	28	22.1	22.8	23.2	23.5	23.9	24.3	24.8
Sierra	CAR	Buckeye	BUC BK 2	25	20.8	22.0	23.0	23.9	24.8	25.8	26.8
Sierra	EAST	Buena Vista	BVV BK 1	2.5	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Sierra	TM	California	CAL BK 1	28	18.6	20.6	22.6	24.4	25.8	27.7	29.5
Sierra	CAR	Carson	CAR BK 1	25	18.1	19.1	19.3	19.7	20.0	20.5	21.0
Sierra	CAR	Carson	CAR BK 2	25	18.1	19.5	21.1	22.6	24.2	25.7	27.3
Sierra	TM	Chukar	CHK BK 1	60	12.4	17.2	17.4	17.5	17.7	19.0	20.3
Sierra	EAST	Coal Canyon	CCN BK 1	7	2.5	2.5	2.7	2.8	2.8	2.9	2.9
Sierra	CAR	Coaldale	CLD BK 1	0.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	EAST	Crescent Valley	CVL BK 1	1.5	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Sierra	CAR	Curry Street	CUR BK 1	14	10.1	10.7	11.0	11.1	11.3	11.6	11.9
Sierra	CAR	Curry Street	CUR BK 2	14	7.0	7.6	8.0	8.3	8.7	9.1	9.5
Sierra	CAR	Dayton	DTN BK 1	14	12.4	12.5	12.7	12.8	13.0	13.2	13.4
Sierra	CAR	Downs	DWN BK 1	28	13.4	13.9	14.2	14.5	14.8	15.2	15.5
Sierra	EAST	Dutch Flat	DHF BK 1	14	13.2	13.2	13.2	13.3	13.5	13.5	13.6
Sierra	EAST	Dutch Flat	DHF BK 2	11.2	6.0	6.0	6.0	6.1	6.1	6.2	6.2
Sierra	FF	Eagle	EGL BK 2	14	7.1	7.4	7.5	7.6	7.7	7.8	8.0
Sierra	FF	Eagle	EGL BK 3	28	21.7	22.4	24.6	24.8	25.0	25.8	26.7
Sierra	EAST	Elko	EKO BK 2	2.5	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Sierra	CAR	Emerson	EMN BK 1	28	22.7	25.3	25.7	26.0	26.4	27.3	28.2
Sierra	FF	Empire	EMP BK 1	1	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Sierra	CAR	Fairview	FVW BK 1	28	23.4	23.9	24.7	25.4	26.1	26.7	27.4
Sierra	FF	Fallon	FLN BK 1	7	4.4	4.4	4.5	4.5	4.6	4.6	4.6
Sierra	FF	Fallon	FLN BK 2	12.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	FF	Fallon	FLN BK 3	14	8.3	8.3	8.4	8.4	8.5	8.6	8.7
Sierra	FF	Fernley	FLY BK 1	28	18.9	26.7	26.9	27.1	27.4	29.5	31.7
Sierra	CAR	Fort Churchill	FTC BK 1	4.32	3.6	3.6	3.6	3.7	3.7	3.7	3.8
Sierra	TM	Fort Sage	FTS BK 1	10	3.2	3.2	3.3	3.3	3.3	3.3	3.4
Sierra	CAR	Gabbs	GBS BK 1	4.7	3.8	3.8	3.8	3.8	3.9	3.9	3.9
Sierra	STAH	Glenbrook	GLN BK 1	5	4.3	4.5	4.5	4.6	4.7	4.8	4.9
Sierra	TM	Glendale	GLD BK 1	40	30.4	30.5	31.0	31.2	31.6	31.9	32.2
Sierra	TM	Glendale	GLD BK 2	60	37.4	41.4	41.8	42.1	42.6	43.9	45.2
Sierra	EAST	Golconda	GOL BK 1	4.687	3.0	3.0	3.1	3.1	3.1	3.1	3.2
Sierra	CAR	Goldfield	GFD BK 1	2.5	1.2	1.5	1.6	1.6	1.6	1.7	1.8
Sierra	EAST	Grass Valley	GRS BK 1	28	19.9	20.1	20.3	20.4	20.8	21.0	21.2
Sierra	TM	Greg Street	GRG BK 1	46.7	28.3	28.6	28.9	29.1	29.4	29.7	29.9
Sierra	TM	Greg Street	GRG BK 2	46.7	38.5	41.3	42.4	42.8	43.2	44.4	45.6
Sierra	TM	Greg Street	GRG BK 3	60	35.9	37.6	38.3	39.0	39.7	40.7	41.7
Sierra	CAR	Hawthorne	HAW BK 1	7	5.8	5.8	5.8	5.9	5.9	6.0	6.0
Sierra	FF	Hazen	HAZ BK 1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Sierra	CAR	Heybourne	HEY BK 1	40	12.2	12.5	12.9	13.2	13.6	13.9	14.3
Sierra	TM	Highland^	HLD BK 1	2.5	1.8	1.8	1.8	1.9	1.9	1.9	1.9
Sierra	TM	Highland^	HLD BK 2	3.125	1.0	1.1	1.1	1.1	1.1	1.2	1.2
Sierra	TM	Holcomb	HOL BK 1	2.5	2.1	2.1	2.2	2.2	2.2	2.2	2.3
Sierra	TM	Holcomb	HOL BK 2	2.5	1.2	1.2	1.2	1.2	1.2	1.3	1.3
Sierra	TM	Holcomb	HOL BK 3	5.26	3.0	3.0	3.0	3.0	3.1	3.1	3.1

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
2023-2029 SUBSTATION TRANSFORMER PEAK FORECAST

Company	Region	Substation	Transformer	Rating (MVA)	2023	2024	2025	2026	2027	2028	2029
Sierra	EAST	Humboldt House	HBH BK 1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	TM	Hunter Lake	HLS BK 1	3.125	2.5	2.5	2.6	2.6	2.7	2.7	2.7
Sierra	TM	Hunter Lake	HLS BK 2	3.125	2.1	2.1	2.1	2.2	2.2	2.2	2.2
Sierra	EAST	Imlay	ILY BK 1	10.5	2.3	2.3	2.3	2.4	2.4	2.4	2.4
Sierra	NTAH	Incline	INC BK 1	28	30.5	31.3	31.7	32.3	32.8	33.4	34.0
Sierra	STAH	Kingsbury	KNG BK 1	12.5	10.1	10.1	10.2	10.3	10.4	10.4	10.5
Sierra	EAST	Kramer Hill	KRH BK 1	7	3.5	3.5	3.5	3.5	3.6	3.6	3.6
Sierra	EAST	Last Chance	LCH BK 1	60	45.5	48.3	48.9	49.4	50.0	51.1	52.2
Sierra	EAST	Limerick	LIM BK 1	1.5	0.7	0.7	0.7	0.7	0.7	0.7	0.8
Sierra	EAST	Lone Mountain^	LNM BK 1	6.25	0.9	0.9	1.0	1.0	1.0	1.0	1.0
Sierra	FF	Lonely	LNY BK 1	28	24.1	24.9	26.5	27.8	28.6	29.7	30.8
Sierra	EAST	Lovelock	LOV BK 1	2.5	1.8	1.8	1.9	1.9	1.9	1.9	1.9
Sierra	EAST	Lovelock	LOV BK 2	3.5	2.9	3.0	3.0	3.0	3.0	3.1	3.1
Sierra	EAST	Lovelock	LOV BK 3	7	0.8	1.0	1.0	1.0	1.0	1.1	1.1
Sierra	CAR	Lower Smoky Valley	LSV BK 1	1.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Sierra	CAR	Luning	LUN BK 1	1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Sierra	CAR	Manhattan	MAN BK 1	5.25	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Sierra	CAR	Mark Twain	MTW BK 1	46.7	25.9	27.4	28.8	30.1	31.3	32.6	34.0
Sierra	CAR	Mason Valley	MNV BK 1	47	15.0	15.1	15.2	15.3	15.4	15.5	15.7
Sierra	CAR	Mason Valley	MNV BK 2	47	11.9	12.2	12.2	12.3	12.4	12.6	12.7
Sierra	TM	McCarran	MCN BK 1	4.687	4.3	4.3	4.3	4.3	4.4	4.4	4.4
Sierra	EAST	McCoy Mine	MCY BK 1	4.687	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Sierra	TM	Mill Street	MIL BK 1	3.75	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Sierra	TM	Mill Street	MIL BK 2	3.125	2.3	2.5	2.6	2.6	2.6	2.7	2.8
Sierra	CAR	Mina	MNA BK 1	1.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Sierra	CAR	Minden	MIN BK 1	9.4	7.9	8.0	8.2	8.2	8.3	8.4	8.6
Sierra	TM	Mira Loma	MIR BK 3	60	50.9	52.3	53.2	53.7	54.5	55.4	56.3
Sierra	TM	Moana	MOA BK 1	2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	TM	Moana	MOA BK 2	3.125	1.9	2.0	2.0	2.0	2.1	2.1	2.2
Sierra	TM	Mount Rose	MTR BK 1	40	35.0	35.6	36.3	36.9	37.6	38.3	38.9
Sierra	TM	Mount Rose	MTR BK 2	33.6	22.3	23.2	23.6	23.9	24.3	24.8	25.3
Sierra	CAR	Muller	MUR BK 1	28	23.3	23.7	24.0	24.3	24.7	25.0	25.3
Sierra	TM	North Red Rock	NRR BK 1	46.7	31.1	33.4	34.8	36.3	37.8	39.5	41.2
Sierra	EAST	North Valmy	NVY BK 1	25	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	EAST	North Valmy	NVY BK 2	25	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Sierra	TM	Northwest^	NOW BK 1	46.7	33.2	34.2	35.6	36.6	37.3	38.3	39.3
Sierra	TM	Northwest^	NOW BK 2	46.7	42.3	43.0	43.7	44.5	45.3	46.0	46.8
Sierra	EAST	Osgood Valley	OSG BK 1	20	2.2	2.2	2.2	2.3	2.3	2.3	2.3
Sierra	CAR	Overland	OVL BK 1	28	18.1	20.5	20.9	21.9	24.7	26.4	28.0
Sierra	EAST	Parran	PAR BK 1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	TM	Patrick	PAT BK 1	60	36.9	49.0	52.6	53.7	54.3	58.6	63.0
Sierra	CAR	Pinenut	PNT BK 1	29	25.3	29.2	29.7	30.3	31.0	32.4	33.9
Sierra	TM	Pyramid	PYD BK 1	3.125	2.6	2.6	2.7	2.7	2.7	2.7	2.8
Sierra	TM	Pyramid	PYD BK 2	3.125	0.6	0.7	0.7	0.8	0.9	1.0	1.1
Sierra	FF	Ray Couch	RYC BK 1	14	6.7	6.9	6.9	7.0	7.0	7.1	7.2
Sierra	FF	Ray Couch	RYC BK 2	14	8.8	9.0	9.1	9.2	9.4	9.5	9.6
Sierra	EAST	Red House	RED BK 1	0.28	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	EAST	Reese River	RRV BK 1	7	3.5	3.6	3.7	3.7	3.8	3.9	3.9
Sierra	TM	Reno	RNO BK 1	6.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Sierra	TM	Reno	RNO BK 2	7	1.5	1.5	1.5	1.5	1.6	1.6	1.6
Sierra	TM	Reno	RNO BK 3	46.7	33.1	35.0	35.8	36.7	37.7	38.8	39.9
Sierra	TM	Reno	RNO BK 4	46.7	31.0	32.8	35.2	37.1	39.0	41.0	43.0
Sierra	EAST	Rose Creek	RCR BK 1	7	2.3	2.3	2.3	2.3	2.3	2.4	2.4
Sierra	STAH	Round Hill	RDH BK 1	25	18.4	19.1	21.9	22.2	22.5	23.5	24.5
Sierra	CAR	Round Mountain	RDM BK 1	20	17.2	17.2	17.3	17.4	17.6	17.7	17.8
Sierra	CAR	Round Mountain	RDM BK 2	20	16.8	16.9	17.0	17.2	17.3	17.5	17.6
Sierra	TM	Rusty Spike	RSK BK 1	46.7	31.2	32.1	33.1	34.1	34.9	35.8	36.7
Sierra	EAST	Rye Patch	RPH BK 1	1	0.3	0.7	0.7	0.8	0.8	0.9	1.0
Sierra	CAR	Sandia	SND BK 1	1.725	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Sierra	CAR	Santa Fe	SFE BK 1	7	1.6	1.6	1.7	1.7	1.7	1.7	1.7

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
2023-2029 SUBSTATION TRANSFORMER PEAK FORECAST

Company	Region	Substation	Transformer	Rating (MVA)	2023	2024	2025	2026	2027	2028	2029
Sierra	EAST	Setty	STY BK 1	14	2.9	3.0	3.0	3.1	3.1	3.1	3.2
Sierra	TM	Silver Lake	SLK BK 1	13.3	12.5	14.0	14.6	15.3	15.9	16.8	17.6
Sierra	TM	Silver Lake	SLK BK 2	46.7	34.6	37.4	39.8	41.5	42.8	44.9	46.9
Sierra	CAR	Silver Peak	SVR BK 1	7	2.8	2.8	5.2	5.2	5.3	5.9	6.6
Sierra	CAR	Silver Springs	SIL BK 1	9.375	8.3	8.6	8.9	9.0	9.1	9.3	9.5
Sierra	CAR	Smith Valley	SVL BK 1	28	19.2	19.3	19.4	19.5	19.7	19.8	20.0
Sierra	EAST	Sonoma Heights	SHT BK 1	1.5	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Sierra	EAST	Sonoma Heights	SHT BK 2	0.75	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Sierra	EAST	Sonoma Heights	SHT BK 3	8.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	TM	South Meadows	SMD BK 1	60	30.6	33.2	35.1	36.7	37.8	39.6	41.5
Sierra	TM	Spanish Springs	SSP BK 1	60	50.9	52.1	54.1	56.0	57.8	59.6	61.3
Sierra	TM	Spanish Springs	SSP BK 2	60	57.8	59.3	61.2	63.1	64.9	66.6	68.4
Sierra	TM	Sparks Industrial	SID BK 1	13.75	8.9	9.0	9.0	9.1	9.2	9.3	9.4
Sierra	CAR	Stagecoach	STA BK 1	4.2	2.5	2.5	2.5	2.5	2.6	2.6	2.6
Sierra	STAH	Stateline	STL BK 1	28	16.6	16.6	16.7	16.8	17.0	17.1	17.1
Sierra	STAH	Stateline	STL BK 3	14	4.6	4.6	4.6	4.7	4.7	4.7	4.8
Sierra	TM	Stead	STD BK 1	13.3	2.9	3.0	5.6	5.6	5.7	6.4	7.0
Sierra	TM	Stead	STD BK 2	14	3.7	3.7	3.8	3.8	3.8	3.9	3.9
Sierra	TM	Steamboat	STM BK 1	46.67	40.3	42.3	44.8	47.1	49.1	51.3	53.5
Sierra	TM	Steamboat	STM BK 2	46.7	28.4	29.1	30.9	32.4	33.0	34.1	35.2
Sierra	CAR	Stickleman	STK BK 1	1	0.8	0.8	0.8	0.8	0.8	0.9	0.9
Sierra	TM	Sugarloaf	SLF BK 1	60	45.5	48.6	52.4	56.2	59.5	63.0	66.4
Sierra	TM	Sugarloaf	SLF BK 2	60	35.0	38.2	40.7	42.8	44.3	46.6	48.9
Sierra	TM	Sutro	SUT BK 1	13.75	5.6	5.7	5.7	5.7	5.8	5.8	5.9
Sierra	EAST	T Lazy S	TLS BK 1	4.687	2.6	2.7	2.8	2.8	2.8	2.9	2.9
Sierra	CAR	Topaz	TPZ BK 1	3.75	4.2	4.2	4.2	4.3	4.3	4.3	4.4
Sierra	EAST	Toulon	TLN BK 1	0.29	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Sierra	TM	Tracy	TCY BK 1	13.3	1.7	1.9	1.9	1.9	1.9	2.0	2.1
Sierra	NTAH	Truckee	TRK BK 1	14	9.7	9.7	9.7	9.8	9.9	9.9	10.0
Sierra	TM	University	UNV BK 1	4.687	0.7	1.3	1.3	1.3	1.3	1.5	1.6
Sierra	TM	Valley Road	VAL BK 2	46.7	46.9	49.9	53.4	56.2	58.3	61.1	63.9
Sierra	TM	Valley Road	VAL BK 3	46.7	20.7	22.8	25.7	26.7	27.0	28.5	30.1
Sierra	TM	Verdi PH	VRD BK 1	2.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra	CAR	Virginia City	VCY BK 1	4.32	2.9	2.9	3.0	3.0	3.0	3.1	3.1
Sierra	FF	Wadsworth	WAD BK 1	5.25	4.2	4.2	4.2	4.2	4.3	4.3	4.3
Sierra	TM	Washoe PH	WSO BK 1	3	1.3	1.3	1.4	1.4	1.4	1.4	1.4
Sierra	TM	West 7th Street	WST BK 1	4.687	3.6	4.1	4.1	4.2	4.2	4.4	4.5
Sierra	CAR	West Tonopah	WTP BK 1	7	6.3	9.1	9.1	9.2	9.3	10.0	10.7
Sierra	FF	Westside^	WES BK 1	14	9.7	9.8	9.8	9.9	10.0	10.1	10.1
Sierra	TM	Wheeler	WLR BK 2	4.6	1.4	1.4	1.5	1.5	1.6	1.6	1.7
Sierra	EAST	Winnemucca	WIN BK 2	28	23.0	23.3	23.6	23.8	24.1	24.3	24.6
Sierra	EAST	Winnemucca	WIN BK 3	0.75	0.5	0.5	0.5	0.5	0.5	0.5	0.5

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
2023-2029 FEEDER PEAK FORECAST

Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	NE	Allen	ALN1201	600	345	345	347	350	354	356	359
Nevada Power	NE	Allen	ALN1203	600	516	516	520	524	530	534	538
Nevada Power	NE	Allen	ALN1204	600	215	241	277	288	299	320	341
Nevada Power	NE	Allen	ALN1205	600	419	434	441	445	450	457	465
Nevada Power	NE	Allen	ALN1206	600	528	538	544	552	562	571	579
Nevada Power	NE	Allen	ALN1210	600	2	2	2	2	2	2	2
Nevada Power	NE	Allen	ALN1212	600	517	541	554	562	572	586	599
Nevada Power	NE	Allen	ALN1213	600	508	513	516	521	527	532	536
Nevada Power	NE	Allen	ALN1214	600	490	497	501	506	513	519	525
Nevada Power	NE	Allen	ALN1215	600	402	404	408	412	418	422	426
Nevada Power	NE	Allen	ALN1217	600	215	260	263	267	271	285	299
Nevada Power	NE	Alta	AL1202	600	496	500	504	509	515	520	524
Nevada Power	NE	Alta	AL1203	585	431	444	460	476	494	509	525
Nevada Power	NE	Alta	AL1205	585	299	300	302	305	309	312	314
Nevada Power	NE	Alta	AL1208	585	193	194	197	199	202	205	207
Nevada Power	NE	Alta	AL1209	585	474	475	479	483	488	492	495
Nevada Power	NE	Alta	AL1210	585	357	358	360	363	367	369	372
Nevada Power	NE	Alta	AL1212	556	369	391	393	396	400	407	415
Nevada Power	NE	Alta	AL1213	530	346	350	354	360	366	371	377
Nevada Power	NE	Alta	AL1214	585	317	327	335	337	340	346	352
Nevada Power	NE	Alta	AL1217	530	44	44	44	44	45	45	45
Nevada Power	NE	Alta	AL1218	530	221	221	222	224	226	227	229
Nevada Power	NE	Andrews	AND1203	600	1	78	297	299	302	377	452
Nevada Power	NE	Andrews	AND1204	600	375	423	508	522	527	565	603
Nevada Power	NE	Andrews	AND1207	600	514	524	527	531	536	541	547
Nevada Power	NE	Andrews	AND1209	600	352	359	361	364	368	372	376
Nevada Power	NE	Andrews	AND1212	600	431	476	483	486	491	506	521
Nevada Power	NE	Andrews	AND1213	600	199	200	201	203	205	207	209
Nevada Power	NE	Andrews	AND1214	600	1	1	1	1	1	1	1
Nevada Power	NE	Andrews	AND1215	600	464	464	466	470	474	477	480
Nevada Power	NE	Andrews	AND1217	600	221	242	246	247	250	257	264
Nevada Power	NW	Angel Peak	AP3402	199	21	21	21	22	22	22	22
Nevada Power	NW	Angel Peak	AP401	150	24	26	26	26	26	27	28
Nevada Power	NW	Angel Peak	AP402	150	16	16	17	17	17	17	17
Nevada Power	NW	Angel Peak	AP403	149	30	30	30	30	31	31	31
Nevada Power	SE	Anthem	ANT1201	600	404	406	410	414	420	424	428
Nevada Power	SE	Anthem	ANT1203	600	152	153	154	155	157	159	160
Nevada Power	SE	Anthem	ANT1204	600	502	507	515	523	534	542	549
Nevada Power	SE	Anthem	ANT1205	600	432	436	442	448	456	462	468
Nevada Power	SE	Anthem	ANT1207	600	507	520	528	537	548	559	569
Nevada Power	SE	Anthem	ANT1209	600	179	180	182	185	188	190	192
Nevada Power	SE	Anthem	ANT1212	600	495	498	503	509	516	522	527
Nevada Power	SE	Anthem	ANT1213	600	379	383	389	396	404	410	417
Nevada Power	SE	Anthem	ANT1214	600	425	429	435	443	451	458	464
Nevada Power	SW	Arden	AD1202	600	342	390	442	489	538	587	636
Nevada Power	SW	Arden	AD1203	600	455	482	542	573	587	621	654
Nevada Power	SW	Arden	AD1204	600	410	490	536	552	564	602	641
Nevada Power	SW	Arden	AD1205	600	473	494	519	541	563	585	608
Nevada Power	SW	Arden	AD1206	600	321	355	425	469	500	545	590
Nevada Power	SW	Arden	AD1207	600	520	544	555	567	578	592	607
Nevada Power	SW	Arden	AD1208	600	298	315	343	372	402	428	455
Nevada Power	NE	Artesian	AR1202	600	239	239	241	242	245	246	247
Nevada Power	NE	Artesian	AR1203	550	383	384	484	487	492	519	547
Nevada Power	NE	Artesian	AR1204	556	282	317	398	401	405	435	466
Nevada Power	NE	Artesian	AR1206	556	441	447	452	455	459	464	468
Nevada Power	NE	Artesian	AR1208	550	360	362	364	366	370	373	375

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	NE	Artesian	AR1210	550	407	474	522	526	531	562	593
Nevada Power	NE	Artesian	AR1211	550	433	443	447	450	455	460	465
Nevada Power	NE	Artesian	AR1213	550	496	521	533	537	544	556	567
Nevada Power	NE	Artesian	AR1214	550	479	482	485	488	493	497	500
Nevada Power	NE	Artesian	AR1215	550	452	453	458	462	466	470	473
Nevada Power	SW	Avera	AVR1205	600	485	490	501	513	527	537	547
Nevada Power	SW	Avera	AVR1206	600	455	467	478	489	499	510	521
Nevada Power	SW	Avera	AVR1208	600	483	499	525	534	542	557	571
Nevada Power	SW	Avera	AVR1209	600	497	566	675	707	717	771	826
Nevada Power	SW	Avera	AVR1210	600	373	426	486	518	552	597	642
Nevada Power	SW	Avera	AVR1215	600	441	451	458	469	482	492	502
Nevada Power	SW	Avera	AVR1216	600	428	440	451	463	476	488	501
Nevada Power	SW	Avera	AVR1217	600	374	451	517	564	598	655	711
Nevada Power	SW	Avera	AVR1221	600	373	410	445	462	476	501	527
Nevada Power	SE	Balboa	BL1201	530	183	184	186	188	191	192	194
Nevada Power	SE	Balboa	BL1203	585	463	476	491	515	541	561	580
Nevada Power	SE	Balboa	BL1204	550	212	216	222	226	229	234	238
Nevada Power	SE	Balboa	BL1207	550	375	381	384	387	392	396	400
Nevada Power	SE	Balboa	BL1208	530	403	417	439	457	469	486	502
Nevada Power	SE	Balboa	BL1209	585	336	387	434	472	500	541	582
Nevada Power	SE	Balboa	BL1210	530	195	202	206	209	213	217	222
Nevada Power	SE	Balboa	BL1211	600	158	166	175	184	193	202	211
Nevada Power	NW	Beltway	BLT1213	417	233	242	243	244	247	250	254
Nevada Power	NW	Beltway	BLT1214	600	131	133	135	138	142	145	148
Nevada Power	NW	Beltway	BLT1216	600	247	250	254	258	263	267	271
Nevada Power	NW	Beltway	BLT1217	600	315	445	544	639	721	823	924
Nevada Power	NW	Beltway	BLT1218	600	391	401	409	417	427	437	446
Nevada Power	NW	Beltway	BLT1219	600	500	508	518	529	542	553	564
Nevada Power	NW	Beltway	BLT1223	600	388	390	395	400	407	411	416
Nevada Power	NW	Beltway	BLT1224	600	0	0	0	0	0	0	0
Nevada Power	SE	Bicentennial	BCT1201	600	288	305	318	332	342	356	370
Nevada Power	SE	Bicentennial	BCT1203	600	422	430	439	449	461	470	480
Nevada Power	SE	Bicentennial	BCT1204	600	405	408	411	416	422	426	430
Nevada Power	SE	Bicentennial	BCT1205	600	523	528	536	544	554	562	570
Nevada Power	SE	Bicentennial	BCT1210	600	383	385	388	393	398	402	406
Nevada Power	SE	Bicentennial	BCT1211	600	273	275	279	283	288	292	295
Nevada Power	SE	Bicentennial	BCT1213	600	18	19	28	40	52	61	69
Nevada Power	SE	Bicentennial	BCT1214	600	400	454	528	603	674	743	811
Nevada Power	SE	Bicentennial	BCT1215	600	485	546	589	629	652	694	736
Nevada Power	SE	Bicentennial	BCT1217	600	398	420	445	472	498	523	548
Nevada Power	SE	Big Bend	BGB2501	400	126	136	136	137	139	142	145
Nevada Power	SE	Big Bend	BGB2507	400	266	266	267	269	272	274	275
Nevada Power	NE	Blade Runner	BLD1202	600	24	24	24	25	25	25	25
Nevada Power	SW	Blue Diamond	BD401	600	1	1	1	1	1	1	1
Nevada Power	SW	Blue Diamond	BD402	600	1	1	1	1	1	1	1
Nevada Power	SW	Blue Diamond	BD403	600	1	1	1	1	1	1	1
Nevada Power	SW	Blue Diamond	BD404	600	1	1	1	1	1	1	1
Nevada Power	SE	Boulder Beach	BB1201	199	89	105	162	163	164	183	202
Nevada Power	SE	Burnham	BRN1201	600	336	338	340	343	347	349	352
Nevada Power	SE	Burnham	BRN1202	600	405	406	408	411	416	419	421
Nevada Power	SE	Burnham	BRN1204	600	403	407	415	424	432	440	447
Nevada Power	SE	Burnham	BRN1205	600	359	360	369	373	377	382	387
Nevada Power	SE	Burnham	BRN1206	600	280	289	318	327	330	343	355
Nevada Power	SE	Burnham	BRN1209	600	437	487	512	526	541	567	593
Nevada Power	SE	Burnham	BRN1210	600	227	229	230	232	234	236	238
Nevada Power	SE	Burnham	BRN1211	600	328	328	330	333	337	339	341

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Burnham	BRN1212	600	408	410	413	417	422	425	429
Nevada Power	SE	Burnham	BRN1214	600	385	396	418	421	425	435	445
Nevada Power	SE	Cabana	CB1201	600	360	361	363	366	370	373	375
Nevada Power	SE	Cabana	CB1202	600	341	348	365	382	401	416	431
Nevada Power	SE	Cabana	CB1204	600	545	549	559	570	582	591	600
Nevada Power	SE	Cabana	CB1205	600	442	442	450	453	458	462	466
Nevada Power	SE	Cabana	CB1206	600	251	251	253	255	258	260	262
Nevada Power	SE	Cabana	CB1209	600	535	542	553	563	574	584	594
Nevada Power	SE	Cabana	CB1210	600	415	416	418	421	425	427	429
Nevada Power	SE	Cabana	CB1211	600	410	410	412	415	419	421	424
Nevada Power	SE	Cabana	CB1212	600	230	230	232	233	236	237	238
Nevada Power	SE	Cabana	CB1214	600	492	492	495	498	503	506	509
Nevada Power	SE	Cactus	CCT1201	600	1	1	1	1	1	1	1
Nevada Power	SE	Cactus	CCT1202	600	349	441	535	562	587	646	706
Nevada Power	SE	Cactus	CCT1207	600	405	405	407	410	414	416	419
Nevada Power	SE	Cactus	CCT1209	600	1	1	1	1	1	1	1
Nevada Power	SE	Cactus	CCT1211	600	481	498	531	563	585	611	637
Nevada Power	SE	Cactus	CCT1212	600	389	431	477	523	535	572	609
Nevada Power	SE	Cactus	CCT1214	600	281	281	282	284	287	289	290
Nevada Power	SE	Cactus	CCT1216	600	1	1	1	1	1	1	1
Nevada Power	SE	Cactus	CCT1217	600	1	1	1	1	1	1	1
Nevada Power	SE	Cactus	CCT1218	600	1	1	1	1	1	1	1
Nevada Power	SW	Camero	CMO1201	600	1	25	359	362	366	457	548
Nevada Power	SW	Camero	CMO1205	600	354	364	451	479	486	518	551
Nevada Power	SW	Camero	CMO1206	600	398	426	471	484	490	513	537
Nevada Power	SW	Camero	CMO1212	600	130	130	130	131	133	133	134
Nevada Power	SW	Camero	CMO1213	600	1	1	1	1	1	1	1
Nevada Power	NW	Canyon	CN3401	199	28	28	29	29	29	29	29
Nevada Power	NE	Carey	CA1201	585	150	150	151	152	153	154	155
Nevada Power	NE	Carey	CA1203	600	243	351	377	379	383	418	453
Nevada Power	NE	Carey	CA1204	600	1	1	1	1	1	1	1
Nevada Power	NE	Carey	CA1207	600	353	369	396	416	436	457	478
Nevada Power	NE	Carey	CA1208	585	247	291	363	365	370	400	431
Nevada Power	NE	Carey	CA1209	600	187	210	263	277	281	304	328
Nevada Power	NE	Carey	CA1211	600	402	402	405	408	413	415	418
Nevada Power	NE	Carey	CA1212	600	337	339	342	346	351	354	358
Nevada Power	NE	Carey	CA1213	600	287	290	292	294	297	300	303
Nevada Power	NE	Carey	CA1215	600	354	358	360	363	367	370	374
Nevada Power	NE	Carey	CA1220	600	142	142	143	144	145	146	147
Nevada Power	NE	Carey	CA1221	600	4	4	4	4	4	4	4
Nevada Power	NW	Charleston	CHR1201	600	328	329	331	333	336	338	340
Nevada Power	NW	Charleston	CHR1202	600	301	305	309	314	320	324	329
Nevada Power	NW	Cheyenne	CHN1202	600	493	494	496	500	506	509	512
Nevada Power	NW	Cheyenne	CHN1204	600	431	434	439	445	453	458	463
Nevada Power	NW	Cheyenne	CHN1205	600	398	399	402	406	412	415	419
Nevada Power	NW	Cheyenne	CHN1207	600	491	493	497	503	509	514	518
Nevada Power	NW	Cheyenne	CHN1208	600	472	473	477	481	487	491	495
Nevada Power	NW	Cheyenne	CHN1210	600	266	268	271	274	279	282	285
Nevada Power	NW	Cheyenne	CHN1211	600	430	431	435	440	446	450	454
Nevada Power	NW	Cheyenne	CHN1212	600	429	431	435	440	447	451	456
Nevada Power	NW	Cheyenne	CHN1214	600	117	117	118	119	120	121	121
Nevada Power	STRIP	Claymont	CM1202	585	155	156	156	158	159	160	161
Nevada Power	STRIP	Claymont	CM1204	585	486	487	491	495	501	504	508
Nevada Power	STRIP	Claymont	CM1205	585	399	399	401	403	407	410	412
Nevada Power	STRIP	Claymont	CM1209	585	463	486	499	502	507	518	529
Nevada Power	STRIP	Claymont	CM1211	585	356	356	359	361	365	367	369

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	STRIP	Claymont	CM1212	585	300	300	301	303	306	308	310
Nevada Power	STRIP	Claymont	CM1223	550	292	294	295	297	300	302	305
Nevada Power	STRIP	Claymont	CM1224	550	369	369	371	374	377	379	381
Nevada Power	STRIP	Claymont	CM1225	550	293	300	429	432	436	472	507
Nevada Power	STRIP	Claymont	CM1228	550	366	372	374	377	380	384	388
Nevada Power	STRIP	Claymont	CM1229	550	429	511	513	517	522	545	569
Nevada Power	STRIP	Claymont	CM1230	550	150	150	151	152	154	155	156
Nevada Power	STRIP	Claymont	CM1231	600	256	256	258	260	262	264	265
Nevada Power	NW	Cold Creek	CC1202	530	123	123	124	124	126	126	127
Nevada Power	NW	Cold Creek	CC1206	530	126	126	127	127	129	129	130
Nevada Power	STRIP	Commerce	COM1205	600	250	338	339	342	345	369	393
Nevada Power	STRIP	Commerce	COM1207	600	266	266	325	350	353	375	397
Nevada Power	STRIP	Commerce	COM1216	600	447	452	462	465	469	475	481
Nevada Power	STRIP	Commerce	COM1218	600	240	240	310	356	360	390	420
Nevada Power	STRIP	Commerce	COM1219	600	435	499	509	513	518	539	560
Nevada Power	STRIP	Concourse	CON1201	600	271	368	509	512	517	579	640
Nevada Power	STRIP	Concourse	CON1203	600	415	459	511	514	519	546	572
Nevada Power	STRIP	Concourse	CON1204	600	259	259	260	262	265	266	267
Nevada Power	STRIP	Concourse	CON1205	600	317	322	323	326	329	332	335
Nevada Power	STRIP	Concourse	CON1206	600	395	427	448	452	456	472	487
Nevada Power	STRIP	Concourse	CON1209	600	87	87	87	88	89	89	89
Nevada Power	STRIP	Concourse	CON1211	600	359	361	363	366	370	373	376
Nevada Power	STRIP	Concourse	CON1212	600	15	15	15	15	15	15	16
Nevada Power	STRIP	Concourse	CON1213	600	231	231	244	245	248	252	256
Nevada Power	STRIP	Concourse	CON1214	600	2	2	2	156	471	588	705
Nevada Power	STRIP	Concourse	CON1215	600	194	194	195	196	198	199	200
Nevada Power	STRIP	Concourse	CON1217	600	467	468	471	475	480	483	487
Nevada Power	NE	Craig	CR1201	600	368	368	394	397	401	410	418
Nevada Power	NE	Craig	CR1203	600	501	501	504	507	512	515	518
Nevada Power	NE	Craig	CR1204	600	482	495	505	516	528	539	551
Nevada Power	NE	Craig	CR1205	600	427	443	460	463	468	478	489
Nevada Power	NE	Craig	CR1206	600	367	406	468	471	476	503	531
Nevada Power	NE	Craig	CR1208	600	435	461	463	467	471	480	489
Nevada Power	NE	Craig	CR1209	585	252	286	297	299	302	314	327
Nevada Power	NE	Craig	CR1211	600	394	467	474	478	484	507	529
Nevada Power	NE	Craig	CR1212	600	510	511	515	519	525	529	532
Nevada Power	NE	Craig	CR1213	600	455	455	458	461	466	468	471
Nevada Power	NE	DeBuono	DEB1203	530	352	354	356	359	363	366	368
Nevada Power	NE	DeBuono	DEB1204	530	355	359	361	364	367	370	374
Nevada Power	NE	DeBuono	DEB1210	530	292	292	295	298	301	304	306
Nevada Power	NE	DeBuono	DEB1214	530	400	401	403	407	412	415	418
Nevada Power	NE	DeBuono	DEB1215	530	405	405	407	411	415	418	421
Nevada Power	NE	DeBuono	DEB1216	530	411	414	417	421	427	430	434
Nevada Power	SW	Decatur	DE1201	550	277	277	279	281	283	285	287
Nevada Power	SW	Decatur	DE1203	550	387	395	399	401	405	410	415
Nevada Power	SW	Decatur	DE1204	550	453	454	456	460	465	468	471
Nevada Power	SW	Decatur	DE1205	470	18	18	18	19	19	19	19
Nevada Power	SW	Decatur	DE1206	470	292	292	295	298	301	304	306
Nevada Power	SW	Decatur	DE1209	550	427	428	431	434	439	442	444
Nevada Power	SW	Decatur	DE1212	600	507	517	520	524	529	535	541
Nevada Power	SW	Decatur	DE1214	600	473	473	476	479	484	487	490
Nevada Power	SW	Durango	DU1201	600	449	465	485	488	494	505	516
Nevada Power	SW	Durango	DU1203	600	494	494	498	502	508	511	515
Nevada Power	SW	Durango	DU1204	600	377	377	378	381	385	387	389
Nevada Power	SW	Durango	DU1205	600	66	66	66	67	68	68	68
Nevada Power	SW	Durango	DU1208	600	499	504	508	512	518	522	527

All values in amps

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SW	Durango	DU1209	600	546	551	562	573	587	597	607
Nevada Power	SW	Durango	DU1210	600	505	507	513	519	527	533	538
Nevada Power	SW	Durango	DU1211	600	402	427	437	441	446	457	468
Nevada Power	SW	Durango	DU1212	600	426	429	434	440	448	453	459
Nevada Power	SW	Durango	DU1215	600	5	5	5	5	5	5	5
Nevada Power	NW	El Capitan	ELC1204	600	276	287	291	294	310	318	327
Nevada Power	NW	El Capitan	ELC1205	600	381	416	421	427	433	447	460
Nevada Power	NW	El Capitan	ELC1208	600	265	366	377	388	398	432	465
Nevada Power	NW	El Capitan	ELC1209	600	441	450	454	459	465	471	477
Nevada Power	NW	El Capitan	ELC1210	600	476	484	491	499	508	516	524
Nevada Power	NW	El Capitan	ELC1215	600	504	544	562	576	590	612	634
Nevada Power	NW	El Capitan	ELC1216	600	468	476	487	496	502	511	520
Nevada Power	NW	El Capitan	ELC1217	600	552	578	586	596	607	621	635
Nevada Power	NW	El Capitan	ELC1218	600	431	545	593	601	610	654	699
Nevada Power	NW	El Capitan	ELC1220	600	1	1	1	1	1	1	1
Nevada Power	NW	El Capitan	ELC1221	600	260	262	265	267	271	274	276
Nevada Power	STRIP	El Rancho	ER1201	585	230	239	240	242	244	248	251
Nevada Power	STRIP	El Rancho	ER1203	585	275	282	292	294	297	302	307
Nevada Power	STRIP	El Rancho	ER1205	585	271	271	273	275	278	279	281
Nevada Power	STRIP	El Rancho	ER1207	585	77	77	77	78	79	79	79
Nevada Power	STRIP	El Rancho	ER1209	585	216	347	349	351	355	390	424
Nevada Power	STRIP	El Rancho	ER1211	550	154	155	156	157	159	160	161
Nevada Power	STRIP	El Rancho	ER1212	530	215	215	216	217	220	221	222
Nevada Power	NW	Elkhorn	ELK1201	600	202	204	206	210	213	216	219
Nevada Power	NW	Elkhorn	ELK1202	600	480	483	556	584	592	620	648
Nevada Power	NW	Elkhorn	ELK1206	600	356	357	359	362	366	368	371
Nevada Power	NW	Elkhorn	ELK1208	600	528	537	548	560	573	584	596
Nevada Power	NW	Elkhorn	ELK1209	600	455	478	500	523	547	569	592
Nevada Power	NW	Elkhorn	ELK1211	600	518	526	535	545	557	566	576
Nevada Power	NW	Elkhorn	ELK1212	600	515	517	526	534	542	548	555
Nevada Power	NW	Elkhorn	ELK1213	600	325	407	521	527	536	588	641
Nevada Power	NW	Elkhorn	ELK1214	600	397	417	437	458	480	501	522
Nevada Power	NW	Elkhorn	ELK1216	600	547	559	569	574	581	589	598
Nevada Power	NW	Elkhorn	ELK1223	600	462	482	517	523	530	548	565
Nevada Power	NW	Elkhorn	ELK1224	600	96	152	196	224	253	292	332
Nevada Power	STRIP	Excalibur	EX1201	600	322	322	324	326	329	331	333
Nevada Power	STRIP	Excalibur	EX1203	600	208	208	209	211	213	214	215
Nevada Power	STRIP	Excalibur	EX1204	600	183	183	184	185	187	188	189
Nevada Power	STRIP	Excalibur	EX1205	600	343	343	345	348	351	353	355
Nevada Power	STRIP	Excalibur	EX1206	600	407	407	409	412	416	418	420
Nevada Power	STRIP	Excalibur	EX1209	600	5	5	5	5	5	5	5
Nevada Power	STRIP	Excalibur	EX1211	600	246	246	247	249	251	252	254
Nevada Power	STRIP	Excalibur	EX1212	585	63	63	63	64	64	65	65
Nevada Power	STRIP	Excalibur	EX1213	585	358	358	360	363	366	368	370
Nevada Power	STRIP	Excalibur	EX1214	585	177	177	177	179	180	181	182
Nevada Power	STRIP	Excalibur	EX1215	585	298	298	299	301	304	306	308
Nevada Power	SE	Faulkner	FLK1204	600	512	537	560	576	591	611	631
Nevada Power	SE	Faulkner	FLK1205	600	420	479	537	547	555	589	623
Nevada Power	SE	Faulkner	FLK1206	600	1	1	1	1	1	1	1
Nevada Power	SE	Faulkner	FLK1208	600	428	501	536	540	545	575	604
Nevada Power	SE	Faulkner	FLK1209	600	324	328	330	333	336	340	343
Nevada Power	SE	Faulkner	FLK1210	600	353	430	489	503	517	558	599
Nevada Power	SE	Faulkner	FLK1215	600	534	541	554	560	567	576	584
Nevada Power	SE	Faulkner	FLK1216	600	162	163	164	166	169	171	172
Nevada Power	SE	Faulkner	FLK1217	600	152	152	153	154	156	157	157
Nevada Power	SE	Faulkner	FLK1218	600	335	392	575	591	604	672	739

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Faulkner	FLK1220	600	181	191	203	215	227	239	250
Nevada Power	SE	Faulkner	FLK1221	600	493	524	542	550	558	574	590
Nevada Power	SE	Faulkner	FLK1224	600	192	210	227	258	290	315	339
Nevada Power	SE	Faulkner	FLK1225	600	131	131	132	133	134	135	135
Nevada Power	SE	Faulkner	FLK1226	600	388	444	513	570	623	682	740
Nevada Power	SE	Faulkner	FLK1227	600	459	486	518	538	554	578	602
Nevada Power	STRIP	Flamingo	FL1202	585	400	401	403	405	409	412	414
Nevada Power	STRIP	Flamingo	FL1203	600	183	183	184	186	187	188	189
Nevada Power	STRIP	Flamingo	FL1206	585	133	133	134	135	136	137	138
Nevada Power	STRIP	Flamingo	FL1207	585	6	62	322	324	328	408	488
Nevada Power	STRIP	Flamingo	FL1208	585	199	199	200	202	204	205	206
Nevada Power	STRIP	Flamingo	FL1209	585	103	103	103	104	105	106	106
Nevada Power	STRIP	Flamingo	FL1211	556	314	441	443	446	451	485	519
Nevada Power	STRIP	Flamingo	FL1212	556	343	449	452	455	460	489	518
Nevada Power	SE	Ford	FRD1204	600	433	439	446	449	454	459	465
Nevada Power	SE	Ford	FRD1208	600	417	434	441	449	459	469	479
Nevada Power	SE	Ford	FRD1209	600	70	70	71	71	72	72	73
Nevada Power	SE	Ford	FRD1210	600	379	380	384	388	393	396	400
Nevada Power	SE	Ford	FRD1216	600	314	355	475	500	505	553	601
Nevada Power	SE	Ford	FRD1217	600	305	316	328	341	354	366	378
Nevada Power	SE	Ford	FRD1218	600	483	485	491	496	501	506	510
Nevada Power	SE	Ford	FRD1220	600	374	390	396	403	411	421	430
Nevada Power	SE	Ford	FRD1221	600	429	434	443	452	459	466	473
Nevada Power	SW	Frias	FRS1206	600	479	498	509	520	533	547	560
Nevada Power	SW	Frias	FRS1210	600	362	378	398	420	443	463	483
Nevada Power	SW	Frias	FRS1211	600	496	502	517	535	554	568	582
Nevada Power	SW	Frias	FRS1212	600	524	536	549	560	573	586	598
Nevada Power	SW	Frias	FRS1214	600	475	480	487	496	506	514	521
Nevada Power	SW	Frias	FRS1215	600	421	453	461	469	479	493	508
Nevada Power	SW	Frias	FRS1217	600	524	533	544	556	568	579	590
Nevada Power	STRIP	Garces	GA1201	470	340	341	343	345	348	351	353
Nevada Power	STRIP	Garces	GA1202	470	248	248	249	251	254	255	256
Nevada Power	STRIP	Garces	GA1204	600	118	205	227	229	231	259	287
Nevada Power	STRIP	Garces	GA1205	600	215	218	295	332	336	366	396
Nevada Power	STRIP	Garces	GA1206	600	420	420	422	425	429	431	433
Nevada Power	STRIP	Garces	GA1209	600	153	153	154	155	157	158	159
Nevada Power	STRIP	Garces	GA1210	600	190	265	273	275	278	300	322
Nevada Power	STRIP	Garces	GA1211	600	1	1	1	1	1	1	1
Nevada Power	NE	Gilmore	GLM1203	600	290	377	440	443	447	487	526
Nevada Power	NE	Gilmore	GLM1204	600	493	546	549	553	559	575	591
Nevada Power	NE	Gilmore	GLM1205	600	594	594	598	602	609	613	616
Nevada Power	NE	Gilmore	GLM1206	600	496	553	557	562	569	588	606
Nevada Power	NE	Gilmore	GLM1211	600	562	567	571	576	582	587	593
Nevada Power	SW	Goodsprings	GS1201	99	18	19	19	19	19	19	19
Nevada Power	SW	Goodsprings	GS1202	99	21	22	22	22	22	22	23
Nevada Power	NE	Grand Teton	GTT1207	600	346	352	358	366	374	381	388
Nevada Power	NE	Grand Teton	GTT1208	600	110	149	237	316	385	454	523
Nevada Power	NE	Grand Teton	GTT1212	600	392	393	397	401	407	411	415
Nevada Power	NE	Grand Teton	GTT1213	600	305	355	393	422	451	488	525
Nevada Power	SE	Green Valley	GV1201	550	410	410	412	415	419	422	424
Nevada Power	SE	Green Valley	GV1203	550	472	473	476	481	486	490	493
Nevada Power	SE	Green Valley	GV1204	600	510	572	581	589	596	618	639
Nevada Power	SE	Green Valley	GV1207	600	362	385	403	412	418	432	446
Nevada Power	SE	Green Valley	GV1208	600	473	478	484	492	501	508	515
Nevada Power	SE	Green Valley	GV1209	600	480	488	498	509	517	526	535
Nevada Power	SE	Green Valley	GV1210	600	455	457	461	466	472	476	480

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Green Valley	GV1211	550	411	414	419	425	433	438	444
Nevada Power	SE	Green Valley	GV1212	550	281	282	284	286	290	292	294
Nevada Power	SE	Green Valley	GV1214	550	407	409	411	414	419	422	425
Nevada Power	SE	Greenway	GNW1201	600	1	1	1	1	1	1	1
Nevada Power	SE	Greenway	GNW1203	600	1	1	1	1	1	2	2
Nevada Power	SE	Greenway	GNW1205	600	389	398	409	415	423	431	440
Nevada Power	SE	Greenway	GNW1206	600	438	442	447	453	460	465	471
Nevada Power	SE	Greenway	GNW1207	600	404	409	416	425	435	442	450
Nevada Power	SE	Greenway	GNW1209	600	533	546	551	557	565	573	580
Nevada Power	NE	Gypsum	GYP1208	600	321	469	510	884	906	1,052	1,199
Nevada Power	NE	Gypsum	GYP1210	600	216	405	516	520	525	602	680
Nevada Power	SE	Haven	HV1202	600	417	427	484	528	536	566	595
Nevada Power	SE	Haven	HV1203	600	420	443	475	479	484	500	516
Nevada Power	SE	Haven	HV1204	600	477	488	492	497	504	511	517
Nevada Power	SE	Haven	HV1205	585	385	385	387	389	393	395	397
Nevada Power	SE	Haven	HV1206	585	277	347	394	397	401	432	464
Nevada Power	SE	Haven	HV1209	600	449	463	500	533	538	560	583
Nevada Power	SE	Haven	HV1210	585	157	164	177	179	181	186	192
Nevada Power	SE	Haven	HV1211	585	403	404	406	409	413	416	418
Nevada Power	SE	Haven	HV1212	600	271	378	458	514	530	595	660
Nevada Power	SE	Haven	HV1213	600	234	387	456	459	464	521	579
Nevada Power	STRIP	Highland	HI1201	550	145	145	145	146	148	149	150
Nevada Power	STRIP	Highland	HI1202	550	269	317	322	324	328	342	357
Nevada Power	STRIP	Highland	HI1203	550	190	190	190	192	194	195	196
Nevada Power	STRIP	Highland	HI1205	550	203	203	204	205	207	208	209
Nevada Power	STRIP	Highland	HI1206	550	452	485	491	495	501	513	525
Nevada Power	STRIP	Highland	HI1209	585	5	5	6	6	6	6	6
Nevada Power	STRIP	Highland	HI1210	550	107	168	205	207	209	234	260
Nevada Power	STRIP	Highland	HI1211	550	371	412	415	418	423	436	449
Nevada Power	STRIP	Highland	HI1214	550	170	170	214	216	218	230	242
Nevada Power	STRIP	Highland	HI1215	600	128	128	129	130	131	132	132
Nevada Power	STRIP	Highland	HI1216	470	269	269	270	272	275	276	278
Nevada Power	STRIP	Highland	HI1217	550	153	154	154	156	157	158	159
Nevada Power	STRIP	Highland	HI1219	600	11	11	11	11	12	12	12
Nevada Power	STRIP	Highland	HI1220	600	374	374	460	486	490	519	548
Nevada Power	STRIP	Highland	HI1222	600	94	169	246	324	348	411	475
Nevada Power	STRIP	Highland	HI1224	600	167	167	168	169	170	171	172
Nevada Power	STRIP	Highland	HI1225	600	181	181	182	183	185	186	187
Nevada Power	STRIP	Highland	HI1226	600	266	342	419	498	524	589	653
Nevada Power	STRIP	Highland	HI1228	470	148	148	149	150	151	152	153
Nevada Power	STRIP	Highland	HI1261	600	5	5	5	5	5	5	5
Nevada Power	STRIP	Highland	HI1263	600	4	4	4	4	4	4	4
Nevada Power	STRIP	Highland	HI1265	600	3	3	3	3	4	4	4
Nevada Power	STRIP	Highland	HI1267	600	4	4	4	4	4	4	4
Nevada Power	NW	Hualapai	HU1201	600	471	473	477	482	488	493	497
Nevada Power	NW	Hualapai	HU1202	600	432	435	440	445	452	457	462
Nevada Power	NW	Hualapai	HU1204	550	406	408	412	417	423	428	432
Nevada Power	NW	Hualapai	HU1205	600	311	312	314	316	320	322	324
Nevada Power	NW	Hualapai	HU1206	600	393	393	395	398	402	404	406
Nevada Power	NW	Hualapai	HU1209	550	326	336	347	358	371	382	394
Nevada Power	NW	Hualapai	HU1210	550	331	333	336	339	344	347	350
Nevada Power	NW	Hualapai	HU1211	600	226	343	372	375	379	417	455
Nevada Power	NW	Hualapai	HU1212	600	392	397	402	408	415	421	427
Nevada Power	NW	Hualapai	HU1214	600	309	312	317	322	328	333	338
Nevada Power	NW	Indian Springs	IS1204	600	278	283	284	287	290	293	296
Nevada Power	NW	Indian Springs	IS401	199	3	3	3	3	3	3	3

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	NW	Indian Springs	IS402	199	231	261	262	264	267	276	285
Nevada Power	NW	Indian Springs	IS403	298	81	91	111	130	150	167	185
Nevada Power	NW	Iron Mountain	IMT1201	600	430	431	435	440	446	450	454
Nevada Power	NW	Iron Mountain	IMT1203	600	371	375	381	388	396	403	409
Nevada Power	NW	Iron Mountain	IMT1204	600	255	258	262	266	271	275	279
Nevada Power	NW	Iron Mountain	IMT1205	600	400	408	414	420	427	434	441
Nevada Power	NW	Iron Mountain	IMT1206	600	180	180	182	183	185	187	188
Nevada Power	NW	Iron Mountain	IMT1209	600	2	2	2	2	2	2	2
Nevada Power	NW	Iron Mountain	IMT1211	600	524	529	537	545	556	564	572
Nevada Power	NW	Iron Mountain	IMT1212	600	553	556	561	568	577	583	589
Nevada Power	SW	Jean	JN1207	530	194	200	266	268	271	290	310
Nevada Power	SW	Jean	JN1208	530	267	267	339	397	401	435	468
Nevada Power	SE	Keehn	KHN1201	600	323	438	519	569	622	696	771
Nevada Power	SE	Keehn	KHN1203	600	17	38	64	75	86	104	121
Nevada Power	SE	Keehn	KHN1204	600	20	27	27	28	29	31	33
Nevada Power	SE	Keehn	KHN1205	600	39	39	39	40	40	40	41
Nevada Power	SE	Keehn	KHN1206	600	328	366	409	424	430	456	481
Nevada Power	SE	Keehn	KHN1210	600	579	642	733	809	826	888	950
Nevada Power	SE	Keehn	KHN1211	600	314	370	476	525	550	609	668
Nevada Power	SE	Keehn	KHN1212	600	257	268	288	308	330	348	367
Nevada Power	SE	Keehn	KHN1213	600	138	186	236	286	318	363	408
Nevada Power	SE	Keehn	KHN1214	600	176	179	183	187	192	196	199
Nevada Power	SE	Keehn	KHN1215	600	151	151	152	153	155	155	156
Nevada Power	SE	Keehn	KHN1217	600	114	114	114	115	116	117	117
Nevada Power	SE	Kidwell	KI1201	149	1	1	1	1	1	1	1
Nevada Power	SE	Kidwell	KI1202	149	43	54	55	55	56	59	62
Nevada Power	NW	Kyle Canyon	KC1201	298	53	59	61	62	64	66	69
Nevada Power	SE	Lake Las Vegas	LLV1201	600	264	285	304	317	325	341	356
Nevada Power	SE	Lake Las Vegas	LLV1203	600	395	413	437	462	483	505	527
Nevada Power	SE	Lake Las Vegas	LLV1205	600	275	282	294	305	317	327	338
Nevada Power	SE	Lake Las Vegas	LLV1206	600	126	151	176	201	221	245	269
Nevada Power	SE	Lake Las Vegas	LLV1209	600	154	210	284	348	412	476	540
Nevada Power	SE	Larson	LRS1201	600	1	11	23	27	27	34	40
Nevada Power	SE	Larson	LRS1202	600	1	1	1	1	1	1	1
Nevada Power	SE	Larson	LRS1206	600	1	1	1	1	1	1	1
Nevada Power	SE	Larson	LRS1207	600	96	209	277	321	351	414	478
Nevada Power	SE	Larson	LRS1208	600	107	157	214	268	314	366	417
Nevada Power	SE	Larson	LRS1209	600	1	1	1	1	1	1	1
Nevada Power	SE	Larson	LRS1211	600	1	67	178	290	404	504	605
Nevada Power	SE	Larson	LRS1212	600	1	211	304	399	470	587	705
Nevada Power	NE	Leavitt	LVT1201	600	542	572	605	611	619	638	657
Nevada Power	NE	Leavitt	LVT1203	600	405	491	546	551	558	596	634
Nevada Power	NE	Leavitt	LVT1204	600	490	500	509	520	532	543	553
Nevada Power	NE	Leavitt	LVT1205	600	537	543	550	558	568	576	583
Nevada Power	NE	Leavitt	LVT1206	600	445	457	461	465	471	477	484
Nevada Power	NE	Leavitt	LVT1209	600	290	290	520	533	539	601	663
Nevada Power	NE	Leavitt	LVT1212	600	451	461	463	467	471	476	482
Nevada Power	NE	Leavitt	LVT1213	600	375	381	387	390	394	399	403
Nevada Power	NE	Leavitt	LVT1214	600	31	31	31	31	32	32	32
Nevada Power	NE	Leavitt	LVT1215	600	558	589	597	601	607	620	632
Nevada Power	STRIP	Lewis	LE402	600	124	124	125	126	127	128	129
Nevada Power	STRIP	Lewis	LE404	600	46	46	47	47	48	48	48
Nevada Power	NE	Lincoln	LCN1203	600	335	336	339	342	347	350	353
Nevada Power	NE	Lincoln	LCN1204	600	432	432	440	443	448	452	456
Nevada Power	NE	Lincoln	LCN1205	600	145	349	434	441	448	524	599
Nevada Power	NE	Lincoln	LCN1206	600	295	323	356	359	362	379	396

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	NE	Lincoln	LCN1210	600	432	476	524	528	533	558	583
Nevada Power	NE	Lincoln	LCN1212	600	13	13	13	13	13	13	13
Nevada Power	NE	Lincoln	LCN1213	600	449	452	454	457	462	465	468
Nevada Power	NE	Lincoln	LCN1214	600	439	439	513	517	522	543	564
Nevada Power	SW	Lindell	LI1202	550	399	405	410	419	428	436	443
Nevada Power	SW	Lindell	LI1204	550	391	392	394	397	402	404	407
Nevada Power	SW	Lindell	LI1207	600	344	352	358	363	370	377	383
Nevada Power	SW	Lindell	LI1208	550	39	42	43	43	44	46	47
Nevada Power	SW	Lindell	LI1211	530	398	406	409	412	416	421	426
Nevada Power	SW	Lindell	LI1212	530	110	111	111	113	114	115	116
Nevada Power	SW	Lindell	LI1213	530	212	221	225	226	229	233	237
Nevada Power	SW	Lindell	LI1220	550	227	241	252	254	256	264	271
Nevada Power	SE	Lindquist	LDQ1203	600	378	412	458	465	471	494	517
Nevada Power	SE	Lindquist	LDQ1204	600	264	303	358	407	449	495	541
Nevada Power	SE	Lindquist	LDQ1205	600	406	434	465	496	529	559	590
Nevada Power	SE	Lindquist	LDQ1208	600	272	277	285	292	301	309	316
Nevada Power	SE	Lindquist	LDQ1210	600	283	284	379	394	398	427	456
Nevada Power	SE	Lindquist	LDQ1215	600	285	308	319	326	334	346	358
Nevada Power	NW	Lone Mountain	LMT1203	600	502	503	507	511	518	522	526
Nevada Power	NW	Lone Mountain	LMT1204	600	485	490	494	499	505	510	515
Nevada Power	NW	Lone Mountain	LMT1211	600	1	1	1	1	1	1	1
Nevada Power	NW	Lone Mountain	LMT1213	600	202	238	267	287	308	335	362
Nevada Power	NW	Lone Mountain	LMT1215	600	426	432	437	441	448	453	458
Nevada Power	NW	Lorenzi	LO1201	585	463	468	474	482	489	495	502
Nevada Power	NW	Lorenzi	LO1203	585	380	473	478	482	488	515	542
Nevada Power	NW	Lorenzi	LO1204	600	425	426	429	433	438	441	444
Nevada Power	NW	Lorenzi	LO1207	585	406	413	439	449	456	469	481
Nevada Power	NW	Lorenzi	LO1208	585	466	467	470	474	480	483	487
Nevada Power	NW	Lorenzi	LO1209	600	534	538	540	544	549	553	557
Nevada Power	NW	Lorenzi	LO1210	585	457	464	471	478	488	495	503
Nevada Power	NW	Lorenzi	LO1211	600	477	478	491	511	520	531	541
Nevada Power	NW	Lorenzi	LO1212	600	306	318	329	340	352	364	375
Nevada Power	NW	Lorenzi	LO1214	600	408	410	413	416	421	425	428
Nevada Power	STRIP	Lynnwood	LY1202	585	493	499	502	505	510	515	519
Nevada Power	STRIP	Lynnwood	LY1204	585	329	329	330	333	336	338	340
Nevada Power	STRIP	Lynnwood	LY1205	420	236	238	240	241	244	246	248
Nevada Power	STRIP	Lynnwood	LY1208	420	235	306	336	339	342	369	396
Nevada Power	STRIP	Lynnwood	LY1209	550	145	145	145	146	148	149	149
Nevada Power	SE	Magic Way	MAG1209	600	529	539	543	548	554	560	567
Nevada Power	SE	Magic Way	MAG1210	600	393	399	404	409	416	421	427
Nevada Power	STRIP	Mayfair	MA1211	550	302	309	311	314	317	321	325
Nevada Power	STRIP	Mayfair	MA1212	550	324	325	328	330	333	335	338
Nevada Power	STRIP	Mayfair	MA1213	585	448	451	453	456	461	464	467
Nevada Power	STRIP	Mayfair	MA1215	585	360	362	365	368	372	375	378
Nevada Power	STRIP	Mayfair	MA1216	585	345	371	378	553	558	611	664
Nevada Power	STRIP	Mayfair	MA1218	585	306	326	328	331	334	341	348
Nevada Power	STRIP	Mayfair	MA401	550	220	220	221	222	225	226	227
Nevada Power	STRIP	Mayfair	MA402	550	287	295	296	298	301	305	308
Nevada Power	SW	McDonald	MCD1205	600	189	189	190	191	193	194	195
Nevada Power	SW	McDonald	MCD1207	600	317	338	357	364	372	386	400
Nevada Power	SW	McDonald	MCD1208	600	322	375	455	501	506	552	598
Nevada Power	SW	McDonald	MCD1210	600	525	572	601	608	616	639	661
Nevada Power	SW	McDonald	MCD1216	600	410	414	459	507	558	595	631
Nevada Power	SW	McDonald	MCD1217	600	418	500	503	506	511	534	558
Nevada Power	SW	McDonald	MCD1218	600	411	422	427	430	434	440	446
Nevada Power	SW	McDonald	MCD1219	600	87	532	546	550	555	672	790

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SW	McDonald	MCD1220	600	431	475	480	486	493	508	523
Nevada Power	STRIP	MGM	MGM1217	600	1	96	150	151	152	190	228
Nevada Power	STRIP	MGM	MGM1218	600	292	292	293	295	298	300	301
Nevada Power	NW	Michael Way	MW1201	600	263	263	264	266	269	270	272
Nevada Power	NW	Michael Way	MW1202	600	348	356	358	361	365	369	373
Nevada Power	NW	Michael Way	MW1204	550	459	460	462	465	470	472	475
Nevada Power	NW	Michael Way	MW1207	600	478	489	501	514	528	541	553
Nevada Power	NW	Michael Way	MW1209	600	241	244	248	252	256	260	264
Nevada Power	NW	Michael Way	MW1211	600	407	426	463	466	472	488	504
Nevada Power	NW	Michael Way	MW1213	600	322	359	441	480	484	525	565
Nevada Power	NE	Miller	MI1202	550	276	276	278	279	282	284	286
Nevada Power	NE	Miller	MI1203	550	297	460	490	494	499	550	601
Nevada Power	NE	Miller	MI1206	585	500	514	524	528	533	542	550
Nevada Power	NE	Miller	MI1207	585	455	456	494	498	502	514	526
Nevada Power	NE	Miller	MI1208	550	174	175	177	179	181	183	185
Nevada Power	SE	Mission	MS1201	530	110	122	149	188	233	264	295
Nevada Power	SE	Mission	MS1203	530	420	423	559	831	844	950	1,056
Nevada Power	SE	Mission	MS1204	530	306	317	327	338	351	362	373
Nevada Power	SE	Mission	MS1205	530	443	455	482	486	492	504	516
Nevada Power	SE	Mission	MS1206	530	276	310	359	388	424	461	497
Nevada Power	SE	Mission	MS1209	550	402	404	408	413	419	423	427
Nevada Power	SE	Mission	MS1210	550	438	460	489	517	534	558	582
Nevada Power	SE	Mission	MS1212	585	280	317	361	382	404	434	465
Nevada Power	SE	Mission	MS1213	530	205	205	206	207	209	210	211
Nevada Power	SE	Mission	MS1214	530	270	270	271	273	276	277	279
Nevada Power	SW	Mountains Edge	MTE1206	600	332	350	366	381	392	407	422
Nevada Power	SW	Mountains Edge	MTE1211	600	513	524	542	561	580	597	614
Nevada Power	SW	Mountains Edge	MTE1212	600	492	501	512	524	537	549	560
Nevada Power	SW	Mountains Edge	MTE1213	600	489	521	549	566	585	608	632
Nevada Power	SW	Mountains Edge	MTE1214	600	377	383	393	404	417	427	437
Nevada Power	SW	Mountains Edge	MTE1215	600	520	531	554	570	584	601	617
Nevada Power	SW	Mountains Edge	MTE1217	600	465	470	477	486	496	504	511
Nevada Power	SW	MYS	MYS1201	600	1	1	1	1	1	1	1
Nevada Power	SW	MYS	MYS1205	600	212	253	295	339	378	419	461
Nevada Power	SW	MYS	MYS1206	600	327	351	373	375	379	392	405
Nevada Power	SW	MYS	MYS1207	600	295	321	349	374	378	399	419
Nevada Power	SW	MYS	MYS1208	600	284	314	346	374	378	402	425
Nevada Power	SW	MYS	MYS1209	600	517	517	519	523	528	531	534
Nevada Power	SW	MYS	MYS1212	600	232	268	305	343	378	414	450
Nevada Power	SW	MYS	MYS1214	600	291	319	348	375	379	400	422
Nevada Power	SW	MYS	MYS1215	600	1	1	1	1	1	1	1
Nevada Power	SW	MYS	MYS1216	600	252	293	336	374	378	409	441
Nevada Power	SW	MYS	MYS1218	600	513	515	519	525	532	536	541
Nevada Power	SE	National Park Service	NPS401	150	18	18	18	18	18	18	18
Nevada Power	NE	Nellis	NS1203	585	187	193	206	207	209	215	220
Nevada Power	NE	Nellis	NS1204	585	22	22	23	23	24	25	25
Nevada Power	NE	Nellis	NS1205	585	379	460	503	511	520	555	590
Nevada Power	NE	Nellis	NS1206	550	444	483	517	521	526	547	567
Nevada Power	NE	Nellis	NS1210	530	1	232	474	477	482	602	722
Nevada Power	NE	Nellis	NS1211	530	392	442	457	461	465	484	502
Nevada Power	SE	Nelson	NL1201	99	3	3	3	3	3	3	3
Nevada Power	NE	North Las Vegas	NLV1202	530	453	460	463	466	471	476	481
Nevada Power	NE	North Las Vegas	NLV1203	530	419	419	421	424	428	431	433
Nevada Power	NE	North Las Vegas	NLV1204	530	194	289	376	379	383	430	477
Nevada Power	NE	North Las Vegas	NLV1209	530	313	376	393	396	400	421	443

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	NE	North Las Vegas	NLV1210	530	474	475	477	480	485	488	491
Nevada Power	NE	North Las Vegas	NLV1211	530	401	443	454	458	462	477	493
Nevada Power	NE	North Las Vegas	NLV1212	530	23	118	150	151	152	184	217
Nevada Power	NW	Northwest	NW1204	600	346	356	370	385	402	416	430
Nevada Power	NW	Northwest	NW1205	600	125	148	180	213	246	277	307
Nevada Power	NW	Northwest	NW1206	600	381	438	467	495	525	561	597
Nevada Power	NW	Northwest	NW1208	600	469	472	477	484	492	497	503
Nevada Power	NW	Northwest	NW1209	600	128	179	225	262	300	343	387
Nevada Power	NW	Northwest	NW1215	600	418	439	505	519	534	564	593
Nevada Power	NW	Northwest	NW1216	600	492	521	548	566	585	608	631
Nevada Power	NW	Northwest	NW1217	600	467	478	488	494	501	510	518
Nevada Power	NW	Northwest	NW1220	600	374	396	423	451	481	507	534
Nevada Power	NW	Northwest	NW1221	600	176	178	190	206	223	234	246
Nevada Power	SW	Oasis	OA1203	550	75	75	75	76	77	77	77
Nevada Power	SW	Oasis	OA1204	550	180	180	181	182	184	185	186
Nevada Power	SW	Oasis	OA1205	530	17	17	77	270	273	337	401
Nevada Power	SW	Oasis	OA1206	550	316	362	383	404	427	454	482
Nevada Power	NE	Olive	OL1202	556	319	325	328	332	337	341	346
Nevada Power	NE	Olive	OL1203	556	463	468	470	473	478	482	486
Nevada Power	STRIP	Oquendo	OQ1203	480	355	390	392	395	399	410	421
Nevada Power	STRIP	Oquendo	OQ1204	480	242	243	244	246	248	249	251
Nevada Power	STRIP	Oquendo	OQ1206	480	295	300	301	303	306	309	312
Nevada Power	STRIP	Oquendo	OQ1209	480	368	370	372	375	378	381	383
Nevada Power	STRIP	Oquendo	OQ1210	480	161	339	383	386	390	447	504
Nevada Power	STRIP	Oquendo	OQ1211	480	121	288	467	471	475	564	653
Nevada Power	STRIP	Oquendo	OQ1213	480	284	300	301	304	307	312	318
Nevada Power	STRIP	Oquendo	OQ1214	480	378	404	406	409	413	422	431
Nevada Power	NE	Pabco	PBC1206	585	399	399	401	404	408	410	412
Nevada Power	NE	Pabco	PBC1208	530	164	171	172	173	175	178	180
Nevada Power	STRIP	Pawnee	PA1202	600	495	511	513	517	522	529	535
Nevada Power	STRIP	Pawnee	PA1203	585	39	39	39	40	40	40	41
Nevada Power	STRIP	Pawnee	PA1204	550	334	340	348	351	355	360	366
Nevada Power	STRIP	Pawnee	PA1206	550	279	285	287	290	293	297	301
Nevada Power	STRIP	Pawnee	PA1207	585	251	282	284	286	288	298	307
Nevada Power	STRIP	Pawnee	PA1208	550	221	239	241	243	246	252	258
Nevada Power	SW	Peace	PCE1201	600	1	1	1	1	1	1	1
Nevada Power	SW	Peace	PCE1204	600	200	233	280	329	378	423	468
Nevada Power	SW	Peace	PCE1206	600	395	410	432	455	480	502	523
Nevada Power	SW	Peace	PCE1209	600	452	457	464	472	482	490	497
Nevada Power	SW	Peace	PCE1211	600	436	447	455	459	464	471	478
Nevada Power	SW	Peace	PCE1213	600	281	289	317	328	334	347	361
Nevada Power	SW	Peace	PCE1214	600	466	469	475	482	491	497	504
Nevada Power	SW	Peace	PCE1215	600	394	394	397	401	406	409	412
Nevada Power	SW	Peace	PCE1217	600	393	431	476	501	506	534	562
Nevada Power	SE	Pearl	PL1201	585	363	363	365	368	371	374	376
Nevada Power	SE	Pearl	PL1202	600	446	449	454	461	468	474	479
Nevada Power	SE	Pearl	PL1204	585	0	1	1	2	2	2	3
Nevada Power	SE	Pearl	PL1206	585	426	441	454	459	464	474	484
Nevada Power	SE	Pearl	PL1209	585	368	372	376	380	386	390	395
Nevada Power	SE	Pearl	PL1211	585	130	132	136	138	141	143	146
Nevada Power	SE	Pearl	PL1213	600	427	429	432	436	442	446	450
Nevada Power	SE	Pearl	PL1214	550	443	445	452	459	467	473	479
Nevada Power	SE	Pebble	PB1201	600	494	495	501	505	512	516	521
Nevada Power	SE	Pebble	PB1203	600	359	362	368	374	382	388	394
Nevada Power	SE	Pebble	PB1204	600	202	206	297	299	302	327	352
Nevada Power	SE	Pebble	PB1205	600	542	544	548	553	561	565	570

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Pebble	PB1209	600	413	421	441	451	462	474	486
Nevada Power	SE	Pebble	PB1210	600	437	439	534	540	548	576	604
Nevada Power	SE	Pebble	PB1211	600	406	444	498	503	508	534	559
Nevada Power	SE	Pebble	PB1212	600	511	515	522	530	538	545	552
Nevada Power	SE	Pebble	PB1213	600	529	530	542	555	569	579	589
Nevada Power	NE	Pecos	PE1201	600	304	458	472	479	487	533	579
Nevada Power	NE	Pecos	PE1202	600	63	180	245	247	249	296	343
Nevada Power	NE	Pecos	PE1207	600	581	631	653	675	683	709	735
Nevada Power	NE	Pecos	PE1208	600	344	357	370	384	391	403	414
Nevada Power	NE	Pecos	PE1209	600	527	528	533	540	547	552	557
Nevada Power	NE	Pecos	PE1211	600	84	90	98	105	114	121	128
Nevada Power	NE	Pecos	PE1212	600	331	342	348	354	361	368	376
Nevada Power	STRIP	Polaris	POL1201	600	169	169	170	171	173	174	175
Nevada Power	STRIP	Polaris	POL1203	600	409	409	411	413	418	420	422
Nevada Power	STRIP	Polaris	POL1204	600	285	306	308	310	313	320	327
Nevada Power	STRIP	Polaris	POL1205	600	108	108	108	109	110	111	111
Nevada Power	STRIP	Polaris	POL1208	600	1	1	1	1	1	1	1
Nevada Power	STRIP	Polaris	POL1209	600	2	2	2	2	2	2	2
Nevada Power	STRIP	Polaris	POL1210	600	98	98	99	100	101	101	102
Nevada Power	STRIP	Polaris	POL1211	600	268	270	325	327	331	346	362
Nevada Power	STRIP	Polaris	POL1212	600	282	466	564	568	573	646	719
Nevada Power	STRIP	Polaris	POL1213	600	408	460	506	510	515	542	569
Nevada Power	STRIP	Polaris	POL1215	600	446	446	451	455	459	462	466
Nevada Power	STRIP	Polaris	POL1216	600	152	152	153	154	156	156	157
Nevada Power	NE	Prince	PR1202	550	424	425	427	430	434	437	439
Nevada Power	NE	Prince	PR1203	550	101	102	103	104	105	105	106
Nevada Power	NE	Prince	PR1206	600	486	486	492	495	500	504	507
Nevada Power	NE	Prince	PR1207	550	243	243	245	246	249	250	252
Nevada Power	NE	Prince	PR1208	550	407	407	410	413	418	420	423
Nevada Power	STRIP	Procyon	PRO1202	600	355	355	357	360	363	365	367
Nevada Power	STRIP	Procyon	PRO1206	600	5	5	5	5	5	5	5
Nevada Power	STRIP	Procyon	PRO1207	600	117	117	118	118	120	120	121
Nevada Power	STRIP	Procyon	PRO1209	600	151	151	152	153	155	155	156
Nevada Power	STRIP	Procyon	PRO1211	600	3	3	3	3	3	3	3
Nevada Power	STRIP	Procyon	PRO1212	600	229	229	230	232	234	235	236
Nevada Power	STRIP	Procyon	PRO1213	600	8	8	8	8	8	8	8
Nevada Power	STRIP	Procyon	PRO1214	600	170	170	171	172	174	174	175
Nevada Power	STRIP	Procyon	PRO1216	600	135	135	135	136	138	138	139
Nevada Power	NE	Prospector	PRS1203	600	84	532	535	539	544	659	774
Nevada Power	SW	Quail	QUL1201	600	366	367	370	373	378	381	384
Nevada Power	SW	Quail	QUL1203	600	305	324	395	465	532	589	646
Nevada Power	SW	Quail	QUL1204	600	327	378	497	568	584	649	713
Nevada Power	SW	Quail	QUL1205	600	507	513	532	557	584	603	622
Nevada Power	SW	Quail	QUL1208	600	485	487	491	496	503	507	511
Nevada Power	SW	Quail	QUL1209	600	198	210	229	249	264	280	297
Nevada Power	SW	Quail	QUL1210	600	507	512	517	524	531	537	544
Nevada Power	SW	Quail	QUL1211	600	292	311	476	582	590	664	739
Nevada Power	SW	Quail	QUL1212	600	266	276	310	334	360	383	406
Nevada Power	SW	Quail	QUL1213	600	190	274	345	369	387	437	486
Nevada Power	NW	Radar	RA1201	199	6	7	7	7	7	7	7
Nevada Power	SW	Railroad	RLR1201	600	62	96	131	166	201	236	270
Nevada Power	SW	Railroad	RLR1203	600	235	235	236	238	240	241	243
Nevada Power	SW	Railroad	RLR1204	600	90	90	91	92	92	93	93
Nevada Power	SW	Railroad	RLR1205	600	220	220	221	222	224	226	227
Nevada Power	SW	Railroad	RLR1206	600	474	494	496	500	505	512	520
Nevada Power	SW	Railroad	RLR1210	600	326	326	328	330	333	335	337

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SW	Railroad	RLR1211	600	473	503	506	509	514	524	535
Nevada Power	SW	Railroad	RLR1212	600	549	558	567	578	589	599	609
Nevada Power	SW	Railroad	RLR1214	600	250	250	251	253	255	257	258
Nevada Power	SW	Railroad	RLR1215	600	265	265	266	268	271	272	273
Nevada Power	SW	Railroad	RLR1217	600	267	267	268	270	273	274	276
Nevada Power	SW	Railroad	RLR1218	600	178	178	179	180	182	183	184
Nevada Power	SW	Railroad	RLR1219	600	254	254	255	257	260	261	262
Nevada Power	NW	Rainbow	RB1202	550	300	300	306	319	331	339	346
Nevada Power	NW	Rainbow	RB1203	585	443	445	449	453	459	463	466
Nevada Power	NW	Rainbow	RB1204	550	342	347	354	361	369	376	383
Nevada Power	NW	Rainbow	RB1207	550	364	365	368	372	377	380	384
Nevada Power	NW	Rainbow	RB1208	585	295	299	304	306	309	313	317
Nevada Power	NW	Rainbow	RB1214	530	107	108	110	112	114	116	118
Nevada Power	NW	Rainbow	RB1215	530	453	454	458	462	468	472	476
Nevada Power	NW	Rainbow	RB1219	585	347	347	349	352	356	358	361
Nevada Power	SE	Ranger	RN1201	150	14	14	14	14	15	15	15
Nevada Power	SE	Ranger	RN1202	150	40	40	40	40	40	41	41
Nevada Power	SW	Red Rock	RRK1201	600	411	412	416	421	427	431	435
Nevada Power	SW	Red Rock	RRK1203	600	348	350	354	358	364	368	372
Nevada Power	SW	Red Rock	RRK1204	600	244	255	343	424	429	476	522
Nevada Power	SW	Red Rock	RRK1211	600	501	505	514	522	531	539	547
Nevada Power	SW	Red Rock	RRK1212	600	378	382	387	394	402	407	413
Nevada Power	SW	Red Rock	RRK1213	600	383	418	430	439	449	465	481
Nevada Power	NW	Regena	RGN1201	600	1	1	1	1	1	1	1
Nevada Power	NW	Regena	RGN1204	600	440	447	458	470	483	494	504
Nevada Power	NW	Regena	RGN1206	600	119	119	120	120	122	122	123
Nevada Power	NW	Regena	RGN1210	600	415	416	419	423	428	431	434
Nevada Power	NW	Regena	RGN1211	600	373	394	428	433	438	454	471
Nevada Power	NW	Regena	RGN1212	600	121	121	122	123	124	125	125
Nevada Power	SW	Riley	RLY1205	600	486	494	505	513	522	531	540
Nevada Power	SW	Riley	RLY1206	600	455	459	470	481	494	504	513
Nevada Power	SW	Riley	RLY1210	600	450	488	531	565	597	634	671
Nevada Power	SW	Riley	RLY1211	600	461	482	500	514	528	545	561
Nevada Power	SW	Riley	RLY1215	600	438	438	447	460	468	476	483
Nevada Power	SW	Riley	RLY1217	600	401	401	403	406	410	412	414
Nevada Power	SE	River Road	RI2501	398	315	316	322	324	327	331	334
Nevada Power	SE	River Road	RI2508	400	108	109	109	110	111	112	113
Nevada Power	SE	River Road	RI2509	400	2	2	2	2	2	2	2
Nevada Power	SW	Robindale	ROB1201	600	555	561	565	570	576	582	587
Nevada Power	SW	Robindale	ROB1203	600	194	255	383	458	462	529	597
Nevada Power	SW	Robindale	ROB1204	600	360	434	467	491	508	545	582
Nevada Power	SW	Robindale	ROB1206	600	362	389	439	488	526	567	608
Nevada Power	SW	Robindale	ROB1210	600	527	530	536	543	551	557	563
Nevada Power	SW	Robindale	ROB1212	600	406	417	438	455	474	491	508
Nevada Power	SW	Robindale	ROB1213	600	421	423	428	433	439	444	448
Nevada Power	SW	Robindale	ROB1214	600	267	342	456	540	556	628	701
Nevada Power	SW	Robindale	ROB1215	600	558	564	572	581	592	601	610
Nevada Power	SW	Robindale	ROB1217	600	446	489	537	554	566	596	626
Nevada Power	SW	Rosanna	RO1201	600	172	173	174	176	178	179	180
Nevada Power	SW	Rosanna	RO1203	600	339	339	341	343	346	348	350
Nevada Power	SW	Rosanna	RO1204	600	356	380	396	406	415	430	444
Nevada Power	SW	Rosanna	RO1207	600	382	384	388	392	398	402	406
Nevada Power	SW	Rosanna	RO1208	600	434	443	453	464	468	477	485
Nevada Power	SW	Rosanna	RO1210	530	364	378	411	423	430	446	463
Nevada Power	SW	Rosanna	RO1212	530	336	388	435	441	449	477	506
Nevada Power	SE	Russell	RS1201	585	244	247	248	250	253	255	257

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Russell	RS1202	585	157	157	158	159	161	162	163
Nevada Power	SE	Russell	RS1204	585	455	459	465	471	476	481	487
Nevada Power	SE	Russell	RS1205	585	498	504	518	525	532	540	548
Nevada Power	SE	Russell	RS1206	600	418	419	422	425	430	433	436
Nevada Power	SE	Russell	RS1209	600	449	474	483	487	492	502	513
Nevada Power	SE	Russell	RS1210	600	419	419	421	424	428	431	433
Nevada Power	SE	Russell	RS1211	600	494	524	552	580	607	635	663
Nevada Power	SE	Russell	RS1212	600	429	430	434	438	444	447	451
Nevada Power	SE	Russell	RS1214	600	196	200	201	203	205	208	210
Nevada Power	SE	Sahara	SA1201	600	402	402	404	406	411	413	415
Nevada Power	SE	Sahara	SA1203	600	479	480	483	490	495	499	503
Nevada Power	SE	Sahara	SA1205	600	376	379	385	387	391	395	399
Nevada Power	SE	Sahara	SA1206	600	406	407	411	416	422	425	429
Nevada Power	SE	Sahara	SA1209	600	335	335	336	339	342	344	346
Nevada Power	SE	Sahara	SA1212	600	436	476	525	528	534	558	583
Nevada Power	SE	Sahara	SA1216	600	402	402	404	407	411	413	415
Nevada Power	SE	Sahara	SA1217	600	80	80	80	81	81	82	82
Nevada Power	STRIP	San Francisco	SF1203	398	276	277	279	281	284	287	289
Nevada Power	STRIP	San Francisco	SF1204	398	240	242	244	247	251	254	257
Nevada Power	STRIP	San Francisco	SF1206	556	387	387	389	392	396	398	400
Nevada Power	STRIP	San Francisco	SF1207	556	450	452	474	477	483	491	499
Nevada Power	STRIP	San Francisco	SF1213	550	333	335	336	339	342	344	347
Nevada Power	STRIP	San Francisco	SF1215	550	172	172	173	174	176	177	178
Nevada Power	STRIP	San Francisco	SF1216	585	283	284	286	288	291	292	294
Nevada Power	STRIP	San Francisco	SF1217	556	271	285	304	307	310	320	329
Nevada Power	STRIP	San Francisco	SF1218	585	279	279	323	325	328	341	353
Nevada Power	SE	Searchlight	SE1201	199	121	128	129	130	131	134	136
Nevada Power	SE	Searchlight	SE1202	298	11	11	11	11	11	11	11
Nevada Power	NE	Shadow	SH1206	585	261	261	262	264	266	268	269
Nevada Power	NE	Shadow	SH1207	585	223	223	226	228	230	232	234
Nevada Power	NE	Shadow	SH1209	585	398	398	401	404	408	411	414
Nevada Power	NE	Shadow	SH1211	585	225	226	256	266	269	280	291
Nevada Power	NE	Shadow	SH1212	585	348	363	420	435	439	462	485
Nevada Power	NE	Shadow	SH401	585	106	129	130	131	132	139	146
Nevada Power	NE	Shadow	SH404	585	336	337	340	342	346	348	350
Nevada Power	NW	Silver Flag	SLV1201	199	4	4	4	4	4	4	5
Nevada Power	STRIP	Sinatra	SNT1206	600	174	174	175	176	178	179	180
Nevada Power	STRIP	Sinatra	SNT1207	600	4	4	4	4	4	4	4
Nevada Power	STRIP	Sinatra	SNT1208	600	168	168	169	170	172	173	174
Nevada Power	STRIP	Sinatra	SNT1215	600	155	155	156	157	159	160	161
Nevada Power	STRIP	Sinatra	SNT1216	600	315	315	316	319	322	324	325
Nevada Power	STRIP	Sinatra	SNT1218	600	364	364	366	369	373	375	377
Nevada Power	STRIP	Sinatra	SNT1219	600	15	15	15	15	15	15	15
Nevada Power	STRIP	Sinatra	SNT1220	600	14	15	15	15	15	15	15
Nevada Power	NW	Skelton	SKL1205	600	418	418	420	423	427	430	432
Nevada Power	NW	Skelton	SKL1206	600	407	409	412	415	420	423	427
Nevada Power	NW	Skelton	SKL1208	600	479	480	482	486	492	495	498
Nevada Power	NW	Skelton	SKL1209	600	464	468	474	481	490	496	502
Nevada Power	NW	Skelton	SKL1210	600	462	475	494	507	521	536	551
Nevada Power	NW	Skelton	SKL1215	600	502	517	537	549	561	576	590
Nevada Power	NW	Skelton	SKL1217	600	242	245	249	253	258	262	266
Nevada Power	NW	Skelton	SKL1218	600	400	423	439	456	474	493	511
Nevada Power	NW	Skelton	SKL1220	600	219	229	233	238	243	249	256
Nevada Power	NW	Skelton	SKL1221	550	417	426	429	433	438	443	448
Nevada Power	NW	Snow Mountain	SN1201	530	92	162	204	206	208	237	265
Nevada Power	SE	Southpoint	SO2502	400	143	143	143	144	146	147	147

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Southpoint	SO2507	400	122	150	151	152	153	161	169
Nevada Power	SE	Southpoint	SO2508	400	19	19	19	20	20	20	20
Nevada Power	SW	Sparta	SPA1205	600	532	538	542	548	556	562	568
Nevada Power	SW	Sparta	SPA1206	600	493	504	526	531	539	550	562
Nevada Power	SW	Sparta	SPA1210	600	400	444	491	539	560	600	640
Nevada Power	SW	Sparta	SPA1213	600	241	305	358	434	465	521	577
Nevada Power	SW	Sparta	SPA1214	600	286	290	296	303	311	317	323
Nevada Power	SW	Sparta	SPA1215	600	322	339	361	383	407	429	450
Nevada Power	SW	Sparta	SPA1217	600	277	283	291	297	304	311	318
Nevada Power	NE	Speedway	SPD1201	600	408	561	576	580	586	631	675
Nevada Power	NE	Speedway	SPD1203	600	493	541	559	563	569	588	606
Nevada Power	NE	Speedway	SPD1204	600	307	307	309	311	314	316	317
Nevada Power	NE	Speedway	SPD1206	600	472	501	503	507	512	522	532
Nevada Power	NE	Speedway	SPD1211	600	313	518	589	593	599	670	741
Nevada Power	NE	Speedway	SPD1213	600	454	480	482	485	490	499	508
Nevada Power	NE	Speedway	SPD1214	600	343	463	465	469	473	506	538
Nevada Power	NE	Speedway	SPD1215	600	172	489	541	550	555	651	747
Nevada Power	STRIP	Spencer	SP1203	530	292	317	427	430	434	469	505
Nevada Power	STRIP	Spencer	SP1206	550	399	399	402	405	409	412	415
Nevada Power	STRIP	Spencer	SP1207	585	252	252	269	271	275	281	287
Nevada Power	STRIP	Spencer	SP1210	550	300	304	308	314	319	323	328
Nevada Power	STRIP	Spencer	SP1211	550	324	328	421	424	429	455	481
Nevada Power	STRIP	Spencer	SP1213	550	342	342	344	347	350	352	354
Nevada Power	STRIP	Spencer	SP1214	530	175	176	177	179	181	182	184
Nevada Power	SW	Spring Mountain	SM1201	199	42	43	52	52	53	56	59
Nevada Power	SW	Spring Mountain	SM1202	530	180	180	181	182	184	185	186
Nevada Power	SW	Spring Valley	SV1201	550	406	450	489	493	499	522	545
Nevada Power	SW	Spring Valley	SV1202	550	300	300	302	305	308	310	312
Nevada Power	SW	Spring Valley	SV1207	550	268	269	272	275	279	282	284
Nevada Power	SW	Spring Valley	SV1209	550	457	457	460	464	469	472	475
Nevada Power	SW	Spring Valley	SV1211	550	458	458	461	464	469	472	475
Nevada Power	SW	Spring Valley	SV1213	550	286	287	288	291	294	296	298
Nevada Power	SW	Spring Valley	SV1214	550	454	455	459	464	470	475	479
Nevada Power	SW	Spring Valley	SV1216	530	370	371	373	376	380	382	384
Nevada Power	STRIP	Strip	STR1203	600	476	496	526	530	535	550	565
Nevada Power	STRIP	Strip	STR1204	600	298	298	300	302	305	306	308
Nevada Power	STRIP	Strip	STR1205	600	142	142	143	144	145	146	147
Nevada Power	STRIP	Strip	STR1206	600	153	154	154	156	157	158	159
Nevada Power	STRIP	Strip	STR1207	600	110	110	110	111	112	113	113
Nevada Power	STRIP	Strip	STR1208	600	3	3	3	3	3	3	4
Nevada Power	STRIP	Strip	STR1215	600	274	274	276	278	281	282	284
Nevada Power	STRIP	Strip	STR1216	600	433	433	435	438	442	445	447
Nevada Power	STRIP	Strip	STR1217	600	147	147	148	149	151	151	152
Nevada Power	STRIP	Strip	STR1218	600	141	141	142	143	144	145	146
Nevada Power	STRIP	Strip	STR1219	600	105	105	106	107	108	108	109
Nevada Power	STRIP	Strip	STR1220	600	1	1	1	1	1	1	1
Nevada Power	NW	Summerlin	SMR1205	470	270	274	280	286	293	299	304
Nevada Power	NW	Summerlin	SMR1207	470	392	395	399	404	411	416	420
Nevada Power	NW	Summerlin	SMR1208	600	471	473	477	482	488	493	497
Nevada Power	NW	Summerlin	SMR1209	600	415	418	423	429	436	441	446
Nevada Power	NW	Summerlin	SMR1210	600	331	350	361	364	368	377	387
Nevada Power	NW	Summerlin	SMR1217	600	418	421	426	432	439	444	449
Nevada Power	NW	Summerlin	SMR1218	600	416	418	422	426	432	436	440
Nevada Power	NW	Summerlin	SMR1219	600	442	444	448	452	459	463	467
Nevada Power	NW	Summerlin	SMR1220	600	430	433	438	444	451	457	462
Nevada Power	SE	Sunset	SUS1201	600	382	403	427	444	461	481	501

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Sunset	SUS1203	600	106	159	226	287	328	383	438
Nevada Power	SE	Sunset	SUS1205	600	521	583	617	648	682	722	762
Nevada Power	SE	Sunset	SUS1206	600	418	425	525	534	542	573	604
Nevada Power	SE	Sunset	SUS1212	600	137	177	216	249	283	320	356
Nevada Power	SE	Sunset	SUS1215	600	1	11	63	116	169	211	253
Nevada Power	STRIP	Suzanne	SZ1201	600	387	387	389	391	395	397	399
Nevada Power	STRIP	Suzanne	SZ1202	550	422	426	433	441	450	457	464
Nevada Power	STRIP	Suzanne	SZ1203	600	358	359	361	363	367	369	371
Nevada Power	STRIP	Suzanne	SZ1205	600	309	346	497	501	506	555	604
Nevada Power	STRIP	Suzanne	SZ1206	550	262	262	263	265	268	269	271
Nevada Power	STRIP	Suzanne	SZ1208	600	176	407	409	412	416	476	536
Nevada Power	STRIP	Suzanne	SZ1209	600	473	473	475	479	483	486	489
Nevada Power	STRIP	Suzanne	SZ1211	600	304	304	306	308	311	313	314
Nevada Power	STRIP	Suzanne	SZ1213	550	374	529	532	535	541	582	624
Nevada Power	STRIP	Suzanne	SZ1214	600	370	373	375	377	381	384	386
Nevada Power	STRIP	Swenson	SWN1201	600	258	258	259	261	264	265	267
Nevada Power	STRIP	Swenson	SWN1206	600	409	471	474	477	482	500	518
Nevada Power	STRIP	Swenson	SWN1207	600	4	4	4	4	4	4	4
Nevada Power	STRIP	Swenson	SWN1208	600	256	257	260	263	267	270	273
Nevada Power	STRIP	Swenson	SWN1209	600	251	251	252	254	257	258	259
Nevada Power	STRIP	Swenson	SWN1211	600	438	516	518	522	527	549	572
Nevada Power	STRIP	Swenson	SWN1213	600	455	484	486	489	494	504	514
Nevada Power	STRIP	Swenson	SWN1214	600	409	471	474	477	482	500	518
Nevada Power	STRIP	Swenson	SWN1216	600	200	200	201	203	205	206	207
Nevada Power	STRIP	Swenson	SWN1219	600	289	289	291	293	296	297	299
Nevada Power	SW	Tam	TA1201	550	356	360	366	372	380	385	391
Nevada Power	SW	Tam	TA1202	530	136	136	137	138	139	140	141
Nevada Power	SW	Tam	TA1204	550	256	257	259	260	263	265	266
Nevada Power	SW	Tam	TA1205	550	385	386	388	391	395	398	401
Nevada Power	SW	Tam	TA1209	550	463	480	482	485	490	497	504
Nevada Power	SW	Tam	TA1210	550	396	396	398	401	405	407	409
Nevada Power	SW	Tam	TA1212	550	356	358	360	362	366	368	371
Nevada Power	NW	Tenaya	TE1201	585	457	460	463	468	474	478	482
Nevada Power	NW	Tenaya	TE1203	600	189	189	190	192	194	195	196
Nevada Power	NW	Tenaya	TE1204	550	280	283	285	287	289	292	294
Nevada Power	NW	Tenaya	TE1205	550	284	284	285	287	290	292	293
Nevada Power	NW	Tenaya	TE1206	550	449	463	488	491	497	509	520
Nevada Power	NW	Tenaya	TE1208	600	152	152	153	154	156	156	157
Nevada Power	NW	Tenaya	TE1209	600	528	529	532	536	542	545	549
Nevada Power	NW	Tenaya	TE1211	600	516	516	519	522	528	530	533
Nevada Power	NW	Tenaya	TE1212	600	413	413	415	418	422	425	427
Nevada Power	NW	Tenaya	TE1213	600	388	390	393	398	403	407	411
Nevada Power	SE	Tolson	TOL1204	600	495	512	534	541	550	564	578
Nevada Power	SE	Tolson	TOL1205	600	523	535	550	565	572	585	597
Nevada Power	SE	Tolson	TOL1206	600	474	477	482	488	496	502	507
Nevada Power	SE	Tolson	TOL1208	600	484	486	490	495	502	507	511
Nevada Power	SE	Tolson	TOL1209	600	327	329	333	338	343	347	351
Nevada Power	SE	Tolson	TOL1215	600	471	472	475	479	485	489	492
Nevada Power	SE	Tolson	TOL1216	600	476	505	542	580	618	653	689
Nevada Power	SE	Tolson	TOL1218	600	200	250	333	380	388	435	482
Nevada Power	SE	Tolson	TOL1220	600	500	501	504	508	513	516	520
Nevada Power	SE	Tolson	TOL1221	600	499	500	504	509	515	519	523
Nevada Power	SW	Tomsik	TOM1201	600	197	253	348	411	450	513	576
Nevada Power	SW	Tomsik	TOM1203	600	1	1	1	1	1	1	1
Nevada Power	SW	Tomsik	TOM1204	600	428	442	478	500	524	548	572
Nevada Power	SW	Tomsik	TOM1210	600	259	394	516	579	604	690	776

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SW	Tomsik	TOM1211	600	67	80	135	188	212	248	284
Nevada Power	SW	Tomsik	TOM1212	600	452	457	462	468	476	482	488
Nevada Power	SW	Tomsik	TOM1213	600	520	526	537	547	556	565	574
Nevada Power	SW	Tomsik	TOM1214	600	506	512	519	528	539	547	555
Nevada Power	SW	Tomsik	TOM1215	600	108	415	417	420	424	504	583
Nevada Power	SW	Tomsik	TOM1217	600	476	483	502	522	543	560	577
Nevada Power	NE	Tonopah	TO1201	585	435	490	540	548	556	587	617
Nevada Power	NE	Tonopah	TO1203	585	477	531	557	567	573	597	621
Nevada Power	NE	Tonopah	TO1204	585	408	411	416	425	435	442	448
Nevada Power	NE	Tonopah	TO1206	585	514	519	522	526	532	536	541
Nevada Power	NE	Tonopah	TO1207	398	55	55	55	56	56	57	57
Nevada Power	NE	Tonopah	TO1209	585	366	393	395	397	401	410	419
Nevada Power	NE	Tonopah	TO1211	585	308	312	318	325	332	339	345
Nevada Power	NE	Tropical	TRO1201	600	513	516	521	527	535	540	546
Nevada Power	NE	Tropical	TRO1203	600	316	347	352	358	365	378	390
Nevada Power	NE	Tropical	TRO1204	600	440	528	571	585	601	641	681
Nevada Power	NE	Tropical	TRO1205	600	483	501	515	525	532	544	556
Nevada Power	NE	Tropical	TRO1206	600	473	475	480	485	492	497	502
Nevada Power	NE	Tropical	TRO1209	600	1	1	1	1	1	1	1
Nevada Power	NE	Tropical	TRO1211	600	385	397	419	441	466	486	506
Nevada Power	NE	Tropical	TRO1212	600	204	206	212	214	216	219	222
Nevada Power	NE	Tropical	TRO1214	600	518	521	526	533	541	547	553
Nevada Power	NE	Tropical	TRO1215	600	468	468	471	475	480	483	486
Nevada Power	NE	Tropical	TRO1217	600	515	583	586	591	598	619	640
Nevada Power	STRIP	Truman	TR1202	550	189	230	361	364	367	412	457
Nevada Power	STRIP	Truman	TR1209	398	15	15	15	15	16	16	16
Nevada Power	STRIP	Truman	TR1210	585	353	377	397	454	459	485	512
Nevada Power	STRIP	Valley View	VV1201	585	302	302	304	306	309	311	312
Nevada Power	STRIP	Valley View	VV1203	550	167	326	447	450	455	527	599
Nevada Power	STRIP	Valley View	VV1204	585	80	80	81	81	82	83	83
Nevada Power	STRIP	Valley View	VV1206	585	500	541	573	577	583	604	624
Nevada Power	STRIP	Valley View	VV1207	600	372	372	374	377	381	383	385
Nevada Power	STRIP	Valley View	VV1209	550	227	340	415	418	422	471	519
Nevada Power	STRIP	Valley View	VV1210	550	385	386	388	390	394	397	399
Nevada Power	STRIP	Valley View	VV1212	550	5	5	5	5	5	5	5
Nevada Power	NW	Vegas	VGS1201	600	392	396	399	404	410	414	419
Nevada Power	NW	Vegas	VGS1203	600	438	441	447	453	461	467	473
Nevada Power	NW	Vegas	VGS1204	600	226	228	231	234	238	241	244
Nevada Power	NW	Vegas	VGS1205	600	388	391	397	404	412	418	424
Nevada Power	NW	Vegas	VGS1206	600	396	397	401	405	411	415	419
Nevada Power	NW	Vegas	VGS1207	600	407	409	412	417	423	427	431
Nevada Power	NW	Vegas	VGS1208	600	261	262	264	266	269	271	273
Nevada Power	NW	Vegas	VGS1211	550	363	390	398	401	405	416	426
Nevada Power	NW	Vegas	VGS1212	550	342	347	352	358	365	370	376
Nevada Power	NW	Vegas	VGS1213	600	414	415	417	420	425	428	430
Nevada Power	NW	Village	VLG1201	600	254	263	273	284	293	303	312
Nevada Power	NW	Village	VLG1203	600	158	161	164	167	171	174	177
Nevada Power	NW	Village	VLG1205	600	1	1	1	1	1	1	1
Nevada Power	NW	Village	VLG1206	600	139	139	140	141	142	143	144
Nevada Power	NW	Village	VLG1210	600	248	248	249	251	254	255	256
Nevada Power	NW	Village	VLG1212	600	115	115	115	116	117	118	119
Nevada Power	NW	Village	VLG1213	600	222	225	230	235	240	245	250
Nevada Power	NW	Village	VLG1215	600	87	87	87	88	89	89	89
Nevada Power	NW	Village	VLG1217	600	391	397	404	413	423	431	439
Nevada Power	SE	Warmsprings	WSP1201	600	416	421	431	443	456	466	475
Nevada Power	SE	Warmsprings	WSP1203	600	348	354	404	448	453	479	506

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Warmsprings	WSP1204	600	385	391	398	406	410	417	423
Nevada Power	SE	Warmsprings	WSP1205	600	149	149	150	151	153	154	154
Nevada Power	SE	Warmsprings	WSP1208	600	292	323	325	327	330	340	349
Nevada Power	SE	Warmsprings	WSP1209	600	473	478	482	488	494	500	505
Nevada Power	SE	Warmsprings	WSP1210	600	423	425	429	434	441	445	450
Nevada Power	SE	Warmsprings	WSP1211	600	386	388	392	396	402	406	409
Nevada Power	SE	Warmsprings	WSP1212	530	449	451	455	460	467	472	476
Nevada Power	SE	Warmsprings	WSP1213	550	460	486	504	509	516	530	544
Nevada Power	NE	Washburn	WSH1201	600	202	202	203	204	206	207	209
Nevada Power	NE	Washburn	WSH1203	600	541	549	558	569	582	592	602
Nevada Power	NE	Washburn	WSH1204	600	530	530	542	546	552	557	563
Nevada Power	NE	Washburn	WSH1205	600	510	511	515	520	526	530	535
Nevada Power	NE	Washburn	WSH1208	600	357	359	360	363	367	369	371
Nevada Power	NE	Washburn	WSH1209	600	413	424	443	457	473	488	503
Nevada Power	NE	Washburn	WSH1210	600	511	524	532	542	554	565	576
Nevada Power	NE	Washburn	WSH1211	600	440	448	455	464	475	484	492
Nevada Power	NE	Washburn	WSH1212	600	490	497	505	515	526	535	544
Nevada Power	NE	Washburn	WSH1213	600	454	470	473	478	484	492	499
Nevada Power	NE	Washington	WN1201	585	318	325	326	328	332	335	339
Nevada Power	NE	Washington	WN1203	585	451	454	456	459	464	467	470
Nevada Power	NE	Washington	WN1204	600	485	486	488	492	498	501	504
Nevada Power	NE	Washington	WN1206	585	201	201	202	204	206	207	208
Nevada Power	NE	Washington	WN1208	585	253	253	254	256	259	260	262
Nevada Power	NE	Washington	WN1209	585	378	382	383	386	390	393	396
Nevada Power	NE	Washington	WN1210	530	357	357	359	361	365	367	369
Nevada Power	NE	Washington	WN1211	585	475	476	479	483	488	492	495
Nevada Power	NE	Washington	WN1213	530	477	521	524	528	533	547	561
Nevada Power	SE	Water Street	WA1201	585	310	363	404	442	476	517	559
Nevada Power	SE	Water Street	WA1203	530	1	1	1	1	1	1	1
Nevada Power	SE	Water Street	WA1204	585	291	299	302	307	311	316	321
Nevada Power	SE	Water Street	WA1206	585	460	504	562	578	586	617	649
Nevada Power	SE	Water Street	WA1208	585	462	478	496	516	537	556	574
Nevada Power	SE	Water Street	WA1209	600	206	271	306	327	349	384	420
Nevada Power	SE	Water Street	WA1210	600	224	231	238	246	252	259	266
Nevada Power	NW	Westside	WE1201	585	455	456	459	463	469	472	475
Nevada Power	NW	Westside	WE1203	585	1	1	1	1	1	1	1
Nevada Power	NW	Westside	WE1204	600	451	452	455	459	464	467	471
Nevada Power	NW	Westside	WE1207	600	483	484	487	491	497	500	504
Nevada Power	NW	Westside	WE1208	585	383	384	387	390	395	398	401
Nevada Power	NW	Westside	WE1209	585	381	383	386	390	395	398	402
Nevada Power	NW	Westside	WE1210	585	451	454	464	538	546	570	594
Nevada Power	NW	Westside	WE1211	585	81	81	82	83	85	85	86
Nevada Power	NW	Westside	WE1212	585	458	463	469	477	486	492	499
Nevada Power	NW	Westside	WE1214	585	493	494	498	502	508	511	515
Nevada Power	NW	Westside	WE1219	600	181	204	205	206	208	215	222
Nevada Power	NW	Westside	WE1220	600	361	364	367	371	376	379	383
Nevada Power	SE	Whitney	WH1201	585	287	289	324	330	335	347	359
Nevada Power	SE	Whitney	WH1202	585	324	325	327	330	334	336	339
Nevada Power	SE	Whitney	WH1203	530	9	9	9	9	9	9	9
Nevada Power	SE	Whitney	WH1204	585	372	382	397	413	427	441	455
Nevada Power	SE	Whitney	WH1206	585	460	469	473	478	485	491	497
Nevada Power	SE	Whitney	WH1209	585	322	337	345	352	356	365	374
Nevada Power	SE	Whitney	WH1211	585	370	399	448	452	458	480	502
Nevada Power	SE	Whitney	WH1213	585	518	524	536	548	563	574	585
Nevada Power	SE	Whitney	WH1214	585	363	364	366	369	373	376	378
Nevada Power	SE	Wigwam	WI1201	600	300	302	304	307	311	314	317

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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Nevada Power	SE	Wigwam	WI1203	600	473	474	478	482	489	492	496
Nevada Power	SE	Wigwam	WI1204	600	489	491	494	499	505	509	513
Nevada Power	SE	Wigwam	WI1205	600	499	502	507	512	519	524	529
Nevada Power	SE	Wigwam	WI1206	600	381	382	385	388	393	396	399
Nevada Power	SE	Wigwam	WI1208	600	189	204	214	225	237	249	261
Nevada Power	SE	Wigwam	WI1209	600	434	435	438	442	447	451	454
Nevada Power	SE	Wigwam	WI1211	600	317	320	324	329	335	339	343
Nevada Power	SE	Wigwam	WI1212	600	485	493	504	516	529	540	551
Nevada Power	SE	Wigwam	WI1213	600	446	508	521	528	533	555	576
Nevada Power	SE	Wilson	WIL1204	600	62	62	62	63	63	64	64
Nevada Power	SE	Wilson	WIL1205	600	188	257	268	275	282	306	329
Nevada Power	SE	Wilson	WIL1206	600	382	392	402	414	425	436	446
Nevada Power	SE	Wilson	WIL1208	600	463	465	469	474	480	484	489
Nevada Power	SE	Wilson	WIL1209	600	449	451	455	461	467	472	477
Nevada Power	SE	Wilson	WIL1210	600	459	462	467	473	481	486	492
Nevada Power	SE	Wilson	WIL1216	600	449	501	520	531	545	569	593
Nevada Power	SE	Wilson	WIL1217	600	319	321	325	329	333	337	341
Nevada Power	SE	Wilson	WIL1218	600	480	481	485	489	496	499	503
Nevada Power	SE	Wilson	WIL1220	600	480	485	489	493	500	504	509
Nevada Power	SE	Wilson	WIL1221	600	353	355	358	362	368	372	375
Nevada Power	SE	Winterwood	WW1203	585	465	465	467	471	475	478	480
Nevada Power	SE	Winterwood	WW1204	585	432	432	434	437	441	443	446
Nevada Power	SE	Winterwood	WW1205	600	157	192	201	202	204	216	227
Nevada Power	SE	Winterwood	WW1207	585	509	524	532	538	544	552	561
Nevada Power	SE	Winterwood	WW1210	600	180	180	181	183	185	187	188
Nevada Power	SE	Winterwood	WW1211	550	364	365	367	369	373	375	378
Nevada Power	SE	Winterwood	WW1214	550	273	275	278	281	285	288	291
Nevada Power	SE	Winterwood	WW1216	600	380	384	389	393	399	404	409
Nevada Power	SE	Winterwood	WW1217	600	452	461	464	468	473	479	484
Nevada Power	SE	Winterwood	WW1219	600	473	473	475	479	483	486	489
Nevada Power	SE	Winterwood	WW1220	600	383	383	386	390	395	397	400
Nevada Power	SE	Winterwood	WW1224	600	294	294	296	298	301	303	304
Nevada Power	SE	Winterwood	WW1225	600	97	97	98	99	100	100	101
Sierra	EAST	Adobe	ADB201	550	63	64	65	67	68	70	71
Sierra	EAST	Adobe	ADB202	550	275	279	283	285	288	291	295
Sierra	EAST	Adobe	ADB203	570	73	74	76	77	78	79	80
Sierra	EAST	Adobe	ADB208	570	259	261	264	268	272	275	279
Sierra	TM	Airport	AIR1	550	1	1	1	1	1	1	1
Sierra	TM	Airport	AIR2	600	1	1	1	1	1	1	1
Sierra	TM	Airport	AIR2006	550	63	64	65	66	66	67	68
Sierra	TM	Airport	AIR242	550	118	133	155	156	158	168	178
Sierra	TM	Airport	AIR265	550	197	202	203	204	206	208	211
Sierra	TM	Airport	AIR266	550	236	236	237	239	241	243	244
Sierra	TM	Airport	AIR267	550	351	400	431	438	447	470	494
Sierra	TM	Airport	AIR269	550	187	200	218	230	240	253	267
Sierra	TM	Airport	AIR282	550	281	281	283	285	287	289	291
Sierra	TM	Airport	AIR283	550	105	114	121	122	123	128	132
Sierra	TM	Airport	AIR3	550	187	187	188	189	191	192	193
Sierra	TM	Airport	AIR4	550	206	209	210	211	213	215	217
Sierra	EAST	Antelope Valley	ANV210	550	147	147	147	148	150	151	151
Sierra	EAST	Antelope Valley	ANV211	570	135	135	136	137	138	139	140
Sierra	FF	Austin	AST201	150	82	93	93	94	95	98	101
Sierra	FF	Austin	AST202	570	29	29	30	30	31	31	31
Sierra	EAST	Battle Mountain	BMT1401	265	236	236	237	239	241	243	244
Sierra	EAST	Battle Mountain	BMT1402	170	21	21	21	21	21	21	21
Sierra	EAST	Battle Mountain	BMT2401	550	93	93	94	95	95	96	96

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Sierra	TM	Bella Vista	BLV271	550	457	459	462	466	471	475	478
Sierra	TM	Bella Vista	BLV282	550	387	387	389	392	396	399	401
Sierra	TM	Bella Vista	BLV283	550	100	100	101	102	103	103	104
Sierra	TM	Bella Vista	BLV284	855	660	701	712	725	739	759	779
Sierra	EAST	Big Springs	BSP213	550	1	1	1	1	1	1	1
Sierra	FF	Brady's	BDY201	175	37	37	37	37	38	38	38
Sierra	CAR	Brunswick	BWK1220	855	236	264	272	281	291	304	318
Sierra	CAR	Brunswick	BWK1223	855	333	334	335	338	341	343	345
Sierra	CAR	Brunswick	BWK1224	855	465	469	474	479	484	489	493
Sierra	CAR	Brunswick	BWK2508	550	193	196	197	198	200	202	204
Sierra	CAR	Buckeye	BUC1275	550	130	134	155	184	215	236	257
Sierra	CAR	Buckeye	BUC1276	550	515	527	541	549	557	568	578
Sierra	CAR	Buckeye	BUC1277	550	103	111	115	118	120	124	128
Sierra	CAR	Buckeye	BUC1278	550	264	294	302	305	308	320	331
Sierra	EAST	Buena Vista	BVV201	265	43	43	43	43	44	44	44
Sierra	EAST	Buena Vista	BVV202	600	1	1	1	1	1	1	1
Sierra	TM	California	CAL2501	550	433	479	526	567	601	643	686
Sierra	CAR	Carson	CAR1230	550	135	135	136	138	140	141	142
Sierra	CAR	Carson	CAR1231	550	408	449	455	462	471	487	503
Sierra	CAR	Carson	CAR1232	550	294	299	305	311	317	323	329
Sierra	CAR	Carson	CAR1233	550	1	1	1	1	1	1	1
Sierra	CAR	Carson	CAR1240	550	190	212	235	257	279	301	323
Sierra	CAR	Carson	CAR1241	550	172	173	184	194	206	214	223
Sierra	CAR	Carson	CAR1242	550	119	119	120	122	123	124	126
Sierra	CAR	Carson	CAR1243	550	381	420	461	500	538	577	617
Sierra	TM	Chukar	CHK2505	550	241	241	242	244	246	247	249
Sierra	TM	Chukar	CHK2506	855	289	400	404	407	411	441	472
Sierra	EAST	Coal Canyon	CCN1201	365	62	62	73	74	74	77	81
Sierra	EAST	Coal Canyon	CCN1202	265	54	54	55	55	56	56	56
Sierra	CAR	Coaldale	CLD1201	175	6	6	6	6	6	6	6
Sierra	EAST	Crescent Valley	CVL220	265	26	26	27	27	27	27	27
Sierra	CAR	Curry Street	CUR1280	550	324	354	370	386	403	423	443
Sierra	CAR	Curry Street	CUR1281	550	325	347	350	353	357	366	374
Sierra	CAR	Curry Street	CUR1282	550	180	186	193	199	202	208	214
Sierra	CAR	Dayton	DTN219	550	288	290	293	297	302	306	309
Sierra	CAR	Downs	DWN1285	550	367	385	395	402	410	421	432
Sierra	CAR	Downs	DWN1286	550	259	265	270	276	282	288	294
Sierra	CAR	Downs	DWN1287	550	1	1	1	1	1	1	1
Sierra	EAST	Dutch Flat	DHF208	570	305	305	307	309	312	314	316
Sierra	EAST	Dutch Flat	DHF209	265	94	94	94	95	96	96	97
Sierra	EAST	Dutch Flat	DHF210	175	46	46	46	46	47	47	47
Sierra	FF	Eagle	EGL1218	550	331	344	348	352	357	364	370
Sierra	FF	Eagle	EGL201	550	138	153	202	204	206	223	240
Sierra	FF	Eagle	EGL202	550	369	369	371	374	377	379	382
Sierra	EAST	Elko	EKO24	550	127	127	128	129	130	131	131
Sierra	EAST	Elko	EKO27	550	88	88	89	89	90	91	91
Sierra	CAR	Emerson	EMN1221	550	162	166	174	183	188	195	202
Sierra	CAR	Emerson	EMN1222	550	249	249	251	253	256	258	260
Sierra	CAR	Emerson	EMN1223	550	358	359	361	364	368	371	373
Sierra	CAR	Emerson	EMN1224	550	327	445	447	451	456	488	520
Sierra	FF	Empire	EMP7001	140	77	87	87	88	89	92	95
Sierra	CAR	Fairview	FVW1210	550	330	335	342	349	357	364	371
Sierra	CAR	Fairview	FVW1211	550	293	306	324	344	361	378	394
Sierra	CAR	Fairview	FVW1212	940	482	488	498	505	511	518	525
Sierra	FF	Fallon	FLN1201	550	238	239	241	243	246	248	250
Sierra	FF	Fallon	FLN1202	310	204	204	206	208	211	213	215

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Sierra	FF	Fallon	FLN1203	230	146	147	148	150	152	153	155
Sierra	FF	Fallon	FLN309	600	1	1	1	1	1	1	1
Sierra	FF	Fallon	FLN310	140	1	1	1	1	1	1	1
Sierra	FF	Fernley	FLY1214	550	147	159	159	160	162	166	170
Sierra	FF	Fernley	FLY1215	550	315	384	388	393	398	419	440
Sierra	FF	Fernley	FLY1216	550	93	370	372	375	379	450	521
Sierra	FF	Fernley	FLY1217	550	327	329	331	334	337	340	343
Sierra	CAR	Fort Churchill	FTC210	550	85	85	85	86	87	87	88
Sierra	TM	Fort Sage	FTS299	570	75	75	75	76	77	77	77
Sierra	CAR	Gabbs	GBS47	550	144	144	145	146	147	148	149
Sierra	CAR	Gabbs	GBS48	1155	857	857	861	867	876	881	885
Sierra	STAH	Glenbrook	GLN2302	570	137	142	144	146	149	152	155
Sierra	STAH	Glenbrook	GLN2505	175	20	21	21	22	22	23	23
Sierra	STAH	Glenbrook	GLN2600	175	35	35	35	35	36	36	36
Sierra	TM	Glendale	GLD211	550	399	407	410	413	417	422	427
Sierra	TM	Glendale	GLD237	550	99	99	100	100	101	102	103
Sierra	TM	Glendale	GLD238	315	84	84	84	85	86	86	86
Sierra	TM	Glendale	GLD245	550	148	150	151	152	154	155	157
Sierra	TM	Glendale	GLD265	550	135	135	142	143	144	146	149
Sierra	TM	Glendale	GLD271	550	250	335	339	342	345	369	393
Sierra	TM	Glendale	GLD274	550	481	484	487	492	497	501	505
Sierra	EAST	Golconda	GOL1201	175	51	51	51	52	52	53	53
Sierra	EAST	Golconda	GOL1202	265	78	78	79	79	80	80	81
Sierra	EAST	Golconda	GOL1203	365	4	4	5	5	5	5	5
Sierra	CAR	Goldfield	GFD1264	350	57	67	74	74	75	79	84
Sierra	EAST	Grass Valley	GRS2517	350	252	254	256	258	261	263	265
Sierra	EAST	Grass Valley	GRS2518	350	233	236	238	240	246	249	252
Sierra	TM	Greg Street	GRG227	470	149	149	149	150	152	153	154
Sierra	TM	Greg Street	GRG228	470	382	389	402	415	427	438	449
Sierra	TM	Greg Street	GRG229	550	359	394	396	398	402	413	424
Sierra	TM	Greg Street	GRG231	550	231	238	240	242	244	248	251
Sierra	TM	Greg Street	GRG232	550	272	331	351	354	357	379	400
Sierra	TM	Greg Street	GRG233	550	405	407	409	413	417	421	424
Sierra	TM	Greg Street	GRG286	550	277	279	281	284	287	289	292
Sierra	TM	Greg Street	GRG287	550	152	152	153	154	156	156	157
Sierra	TM	Greg Street	GRG288	550	276	282	283	286	289	292	295
Sierra	CAR	Hawthorne	HAW1201	350	122	123	123	124	125	126	127
Sierra	CAR	Hawthorne	HAW1202	350	148	148	149	150	151	152	153
Sierra	FF	Hazen	HAZ1210	265	13	13	14	14	14	14	14
Sierra	CAR	Heybourne	HEY1287	550	274	275	277	279	282	284	286
Sierra	CAR	Heybourne	HEY1288	855	256	268	283	295	309	322	335
Sierra	CAR	Heybourne	HEY1289	855	1	1	1	1	1	1	1
Sierra	CAR	Heybourne	HEY1290	550	74	74	75	76	77	78	79
Sierra	TM	Highland^	HLD1	355	152	152	153	154	156	157	158
Sierra	TM	Highland^	HLD2	355	100	101	103	105	107	109	111
Sierra	TM	Highland^	HLD3	384	70	73	76	79	83	86	89
Sierra	TM	Highland^	HLD4	550	76	76	76	77	78	78	79
Sierra	TM	Holcomb	HOL1	310	72	75	75	75	76	77	78
Sierra	TM	Holcomb	HOL2	310	202	212	213	214	216	220	224
Sierra	TM	Holcomb	HOL3	350	1	1	1	1	1	1	1
Sierra	TM	Holcomb	HOL4	350	157	158	160	162	165	167	169
Sierra	TM	Holcomb	HOL5	384	233	237	239	242	246	249	252
Sierra	TM	Holcomb	HOL6	384	159	159	160	161	162	163	164
Sierra	EAST	Humboldt House	HBH701	140	11	11	11	11	11	11	11
Sierra	TM	Hunter Lake	HLS1	475	198	199	201	204	207	210	212
Sierra	TM	Hunter Lake	HLS2	475	150	153	156	160	164	167	171

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Sierra	TM	Hunter Lake	HLS3	475	294	297	299	303	307	310	314
Sierra	TM	Hunter Lake	HLS4	475	1	1	1	1	1	1	1
Sierra	EAST	Imlay	ILY1201	365	109	109	110	110	111	112	113
Sierra	NTAH	Incline	INC4100	550	513	528	539	552	562	574	586
Sierra	NTAH	Incline	INC4200	550	498	512	518	526	535	544	554
Sierra	NTAH	Incline	INC4300	550	304	305	307	309	313	315	317
Sierra	STAH	Kingsbury	KNG2800	570	407	407	409	412	416	418	420
Sierra	EAST	Kramer Hill	KRH1204	340	153	153	154	155	156	157	158
Sierra	EAST	Last Chance	LCH211	550	421	428	436	443	449	456	462
Sierra	EAST	Last Chance	LCH212	550	206	209	210	212	214	217	219
Sierra	EAST	Last Chance	LCH218	550	257	309	311	313	317	332	347
Sierra	EAST	Last Chance	LCH221	550	231	236	237	239	241	243	246
Sierra	EAST	Limerick	LIM1201	175	31	31	32	32	32	33	33
Sierra	EAST	Lone Mountain^	LNM1201	315	44	44	45	45	45	46	46
Sierra	FF	Lonely	LNY1230	550	472	478	484	488	494	499	505
Sierra	FF	Lonely	LNY1231	550	257	264	274	285	297	307	317
Sierra	FF	Lonely	LNY1232	550	214	227	271	306	310	334	358
Sierra	FF	Lonely	LNY1233	550	178	188	199	211	224	236	247
Sierra	EAST	Lovelock	LOV1203	230	37	45	46	46	47	50	52
Sierra	EAST	Lovelock	LOV701	315	147	148	148	149	151	152	153
Sierra	EAST	Lovelock	LOV702	315	45	45	46	46	46	47	47
Sierra	EAST	Lovelock	LOV703	175	194	198	199	200	202	205	207
Sierra	CAR	Lower Smoky Valley	LSV1260	175	37	37	38	38	38	38	39
Sierra	CAR	Luning	LUN7005	600	14	14	14	14	14	14	14
Sierra	CAR	Manhattan	MAN1201	350	36	36	36	36	37	37	37
Sierra	CAR	Mark Twain	MTW218	550	295	304	318	330	342	354	365
Sierra	CAR	Mark Twain	MTW220	550	310	337	354	372	387	407	426
Sierra	CAR	Mason Valley	MNV2501	550	318	320	322	324	328	330	332
Sierra	CAR	Mason Valley	MNV2506	550	98	98	98	99	100	101	101
Sierra	CAR	Mason Valley	MNV2507	550	275	281	283	285	288	291	294
Sierra	CAR	Mason Valley	MNV2508	550	1	1	1	1	1	1	1
Sierra	TM	McCarran	MCN1	550	403	403	405	408	412	414	416
Sierra	TM	McCarran	MCN2	550	194	194	195	197	199	200	201
Sierra	EAST	McCoy Mine	MCY201	175	28	28	28	28	29	29	29
Sierra	TM	Mill Street	MIL1	475	339	343	346	350	355	359	362
Sierra	TM	Mill Street	MIL2	384	31	31	31	32	32	32	32
Sierra	TM	Mill Street	MIL3	475	327	353	356	359	364	374	383
Sierra	CAR	Mina	MNA1202	350	9	9	9	9	9	9	9
Sierra	CAR	Mina	MNA1203	350	8	8	8	8	8	8	9
Sierra	CAR	Mina	MNA1204	170	2	2	2	2	2	2	2
Sierra	CAR	Minden	MIN1271	350	1	1	1	1	1	1	1
Sierra	CAR	Minden	MIN1272	550	131	132	133	134	136	137	138
Sierra	CAR	Minden	MIN1273	550	234	239	245	247	250	254	257
Sierra	CAR	Minden	MIN1275	550	1	1	1	1	1	1	1
Sierra	TM	Mira Loma	MIR2502	550	474	489	495	499	504	511	519
Sierra	TM	Mira Loma	MIR2503	550	266	268	271	275	280	284	287
Sierra	TM	Mira Loma	MIR2504	550	478	495	505	511	519	529	540
Sierra	TM	Moana	MOA2	384	10	10	10	10	10	11	11
Sierra	TM	Moana	MOA3	475	267	272	279	284	291	297	303
Sierra	TM	Moana	MOA4	480	1	1	1	1	1	1	1
Sierra	TM	Mount Rose	MTR203	570	224	228	234	240	247	253	259
Sierra	TM	Mount Rose	MTR210	550	354	371	378	381	385	393	401
Sierra	TM	Mount Rose	MTR242	855	263	267	271	275	280	284	288
Sierra	TM	Mount Rose	MTR243	550	249	253	257	261	266	270	274
Sierra	TM	Mount Rose	MTR282	550	349	354	359	364	369	375	380
Sierra	CAR	Muller	MUR1295	550	360	369	374	378	382	388	393

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
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Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Sierra	CAR	Muller	MUR1296	855	728	737	749	759	770	780	790
Sierra	TM	North Red Rock	NRR2503	550	429	455	483	512	541	569	598
Sierra	TM	North Red Rock	NRR2504	550	294	322	326	332	338	349	360
Sierra	EAST	North Valmy	NVY2401	175	1	1	1	1	1	1	1
Sierra	EAST	North Valmy	NVY2402	550	30	30	30	30	31	31	31
Sierra	EAST	North Valmy	NVY2403	600	34	34	34	34	35	35	35
Sierra	EAST	North Valmy	NVY2404	230	1	1	1	1	1	1	1
Sierra	TM	Northwest^	NOW206	550	170	178	190	198	200	207	214
Sierra	TM	Northwest^	NOW207	550	312	317	324	330	335	341	347
Sierra	TM	Northwest^	NOW208	550	345	351	357	365	372	379	386
Sierra	TM	Northwest^	NOW216	550	433	440	449	453	459	466	472
Sierra	TM	Northwest^	NOW218	550	171	178	190	202	209	218	228
Sierra	TM	Northwest^	NOW244	550	436	441	446	451	457	463	468
Sierra	EAST	Osgood Valley	OSG201	350	22	22	22	22	22	23	23
Sierra	EAST	Osgood Valley	OSG202	550	41	41	42	42	42	43	43
Sierra	CAR	Overland	OVL1250	550	76	91	92	93	94	99	104
Sierra	CAR	Overland	OVL1260	550	128	132	135	138	140	143	146
Sierra	CAR	Overland	OVL1265	550	474	481	491	523	646	690	733
Sierra	CAR	Overland	OVL1270	855	161	248	253	259	266	292	318
Sierra	EAST	Parran	PAR724	50	3	3	3	3	3	3	3
Sierra	TM	Patrick	PAT224	855	101	131	136	137	139	148	157
Sierra	TM	Patrick	PAT225	855	474	723	800	823	832	921	1,011
Sierra	TM	Patrick	PAT226	550	291	292	294	296	299	301	303
Sierra	CAR	Pinenut	PNT1251	550	415	418	422	427	433	437	441
Sierra	CAR	Pinenut	PNT1252	600	1	140	141	142	143	179	214
Sierra	CAR	Pinenut	PNT1253	550	482	495	506	519	533	545	558
Sierra	CAR	Pinenut	PNT1254	550	285	309	319	329	339	353	366
Sierra	TM	Pyramid	PYD1	550	220	226	231	233	235	239	243
Sierra	TM	Pyramid	PYD2	550	138	138	139	140	141	142	143
Sierra	TM	Pyramid	PYD3	384	73	78	89	101	112	122	132
Sierra	TM	Pyramid	PYD4	384	15	15	15	15	16	16	16
Sierra	FF	Ray Couch	RYC1206	550	138	139	140	141	142	144	145
Sierra	FF	Ray Couch	RYC1207	550	409	418	423	428	434	440	446
Sierra	FF	Ray Couch	RYC1208	550	174	179	180	182	184	187	189
Sierra	EAST	Red House	RED1401	175	4	4	4	4	4	4	4
Sierra	EAST	Reese River	RRV230	265	71	73	75	75	76	78	79
Sierra	EAST	Reese River	RRV231	265	28	29	29	29	29	30	30
Sierra	TM	Reno	RNO1	550	81	81	81	82	82	83	83
Sierra	TM	Reno	RNO204	570	141	155	161	168	173	182	190
Sierra	TM	Reno	RNO216	550	154	169	170	171	172	177	182
Sierra	TM	Reno	RNO217	170	1	1	1	1	1	1	1
Sierra	TM	Reno	RNO240	550	371	378	382	386	392	397	402
Sierra	TM	Reno	RNO243	570	250	251	253	256	259	262	264
Sierra	TM	Reno	RNO247	560	224	239	249	258	269	281	292
Sierra	TM	Reno	RNO263	560	245	267	307	344	379	413	446
Sierra	TM	Reno	RNO285	550	196	209	221	226	230	239	247
Sierra	TM	Reno	RNO4	384	95	95	95	96	97	98	98
Sierra	TM	Reno	RNO6	384	113	114	116	118	121	123	124
Sierra	EAST	Rose Creek	RCR201	175	53	53	54	54	54	55	55
Sierra	STAH	Round Hill	RDH1502	550	251	261	272	280	285	293	301
Sierra	STAH	Round Hill	RDH1503	550	273	277	278	280	283	285	288
Sierra	STAH	Round Hill	RDH1504	550	238	250	350	354	359	389	419
Sierra	CAR	Round Mountain	RDM2220	350	100	104	105	106	107	109	111
Sierra	CAR	Round Mountain	RDM2221	570	400	400	402	405	409	411	413
Sierra	CAR	Round Mountain	RDM2222	1155	329	329	331	333	336	338	340
Sierra	TM	Rusty Spike	RSK221	550	66	72	78	84	87	93	98

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
2023-2029 FEEDER PEAK FORECAST

Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Sierra	TM	Rusty Spike	RSK254	550	430	442	456	469	480	492	504
Sierra	TM	Rusty Spike	RSK260	550	282	285	289	294	298	302	305
Sierra	EAST	Rye Patch	RPH21	350	72	179	180	182	183	211	239
Sierra	CAR	Sandia	SND1201	350	47	47	47	48	48	49	49
Sierra	CAR	Santa Fe	SFE1201	175	70	70	71	71	72	72	73
Sierra	EAST	Setty	STY2402	365	56	56	56	56	57	57	58
Sierra	EAST	Setty	STY251	550	11	14	14	14	15	15	16
Sierra	TM	Silver Lake	SLK255	550	288	303	311	316	321	329	338
Sierra	TM	Silver Lake	SLK256	550	234	234	235	237	239	240	242
Sierra	TM	Silver Lake	SLK257	550	291	325	339	354	369	389	409
Sierra	TM	Silver Lake	SLK258	550	288	336	383	416	439	477	515
Sierra	TM	Silver Lake	SLK259	550	1	1	1	1	1	1	1
Sierra	CAR	Silver Peak	SVR203	350	66	67	123	124	125	140	154
Sierra	CAR	Silver Springs	SIL1211	550	334	343	346	348	352	357	361
Sierra	CAR	Silver Springs	SIL1212	550	61	68	78	80	81	86	91
Sierra	CAR	Smith Valley	SVL2501	550	168	168	169	170	172	173	174
Sierra	CAR	Smith Valley	SVL2502	550	67	68	69	69	70	70	71
Sierra	CAR	Smith Valley	SVL2504	550	65	65	65	66	66	67	67
Sierra	CAR	Smith Valley	SVL2506	550	166	167	168	169	171	172	173
Sierra	EAST	Sonoma Heights	SHT206	350	1	1	1	1	1	1	1
Sierra	EAST	Sonoma Heights	SHT21	570	176	176	176	178	180	180	181
Sierra	EAST	Sonoma Heights	SHT23	350	128	128	129	130	131	132	133
Sierra	EAST	Sonoma Heights	SHT704	350	34	34	35	35	35	35	36
Sierra	TM	South Meadows	SMD2503	600	399	441	461	481	499	524	549
Sierra	TM	South Meadows	SMD2504	600	309	328	352	369	377	394	411
Sierra	TM	Spanish Springs	SSP270	855	437	443	451	459	469	477	485
Sierra	TM	Spanish Springs	SSP271	550	274	274	276	278	281	283	285
Sierra	TM	Spanish Springs	SSP272	550	383	386	389	392	397	400	403
Sierra	TM	Spanish Springs	SSP273	855	477	499	536	568	599	629	659
Sierra	TM	Spanish Springs	SSP274	550	255	261	265	268	272	276	280
Sierra	TM	Spanish Springs	SSP275	855	703	730	767	805	838	872	905
Sierra	TM	Sparks Industrial	SID211	550	1	1	1	1	1	1	1
Sierra	TM	Sparks Industrial	SID229	550	1	1	1	1	1	1	1
Sierra	TM	Sparks Industrial	SID261	550	203	206	207	209	211	213	215
Sierra	TM	Sparks Industrial	SID274	550	1	1	1	1	1	1	1
Sierra	CAR	Stagecoach	STA217	265	58	59	59	59	60	60	61
Sierra	STAH	Stateline	STL2001	600	1	1	1	1	1	1	1
Sierra	STAH	Stateline	STL2200	550	241	241	242	244	246	247	249
Sierra	STAH	Stateline	STL2300	550	214	214	215	216	218	219	221
Sierra	STAH	Stateline	STL3101	550	185	185	186	187	189	190	191
Sierra	STAH	Stateline	STL3501	550	213	213	214	215	218	219	220
Sierra	TM	Stead	STD255	550	1	1	1	1	1	1	1
Sierra	TM	Stead	STD257	550	74	75	135	136	138	154	170
Sierra	TM	Stead	STD259	550	86	86	87	87	88	89	89
Sierra	TM	Steamboat	STM210	570	386	393	398	404	411	417	423
Sierra	TM	Steamboat	STM212	570	427	449	482	518	551	582	613
Sierra	TM	Steamboat	STM213	550	326	336	340	345	350	356	362
Sierra	TM	Steamboat	STM214	550	197	204	239	268	271	290	308
Sierra	TM	Steamboat	STM215	550	98	99	101	103	105	106	108
Sierra	TM	Steamboat	STM219	315	1	1	1	1	1	1	1
Sierra	TM	Steamboat	STM268	570	198	213	234	245	255	270	284
Sierra	CAR	Stickleman	STK1201	350	38	38	38	38	39	39	39
Sierra	TM	Sugarloaf	SLF2505	550	262	285	315	345	363	388	413
Sierra	TM	Sugarloaf	SLF2509	940	726	781	837	881	914	961	1,008
Sierra	TM	Sugarloaf	SLF2510	550	102	121	124	127	130	136	143
Sierra	TM	Sugarloaf	SLF301	550	200	238	279	320	360	400	440

NEVADA POWER COMPANY AND SIERRA PACIFIC POWER COMPANY
2023-2029 FEEDER PEAK FORECAST

Company	Region	Substation	Feeder	Rating (amps)	2023	2024	2025	2026	2027	2028	2029
Sierra	TM	Sugarloaf	SLF303	647	595	607	622	639	658	674	689
Sierra	TM	Sutro	SUT211	550	1	1	1	1	1	1	1
Sierra	TM	Sutro	SUT241	480	130	132	132	133	135	136	137
Sierra	EAST	T Lazy S	TLS240	265	60	63	64	64	65	66	68
Sierra	CAR	Topaz	TPZ1261	265	196	196	196	198	200	201	202
Sierra	EAST	Toulon	TLN701	170	8	9	9	9	9	9	9
Sierra	TM	Tracy	TCY277	150	0	0	0	0	0	0	0
Sierra	TM	Tracy	TCY278	550	42	45	46	46	47	48	49
Sierra	NTAH	Truckee	TRK7202	315	22	22	22	23	23	23	23
Sierra	NTAH	Truckee	TRK7203	570	323	323	324	327	330	332	333
Sierra	NTAH	Truckee	TRK7204	570	54	54	55	55	55	56	56
Sierra	TM	University	UNV2	475	99	180	181	182	184	205	226
Sierra	TM	Valley Road	VAL244	395	11	12	13	13	14	14	15
Sierra	TM	Valley Road	VAL246	470	202	202	203	204	206	207	208
Sierra	TM	Valley Road	VAL248	395	318	347	381	389	393	412	431
Sierra	TM	Valley Road	VAL249	550	398	440	487	519	541	577	613
Sierra	TM	Valley Road	VAL251	395	159	179	210	225	227	244	261
Sierra	TM	Valley Road	VAL254	395	62	77	102	128	147	168	189
Sierra	TM	Valley Road	VAL262	470	429	440	448	453	459	466	474
Sierra	TM	Verdi PH	VRD204	175	1	1	1	1	1	1	1
Sierra	CAR	Virginia City	VCY213	265	4	5	5	5	5	5	6
Sierra	CAR	Virginia City	VCY214	265	28	29	29	29	30	30	31
Sierra	CAR	Virginia City	VCY215	350	35	35	35	35	36	36	36
Sierra	FF	Wadsworth	WAD1220	265	69	69	70	70	71	71	71
Sierra	FF	Wadsworth	WAD1221	365	125	125	125	126	127	128	129
Sierra	TM	Washoe PH	WSO201	150	30	30	31	31	31	31	31
Sierra	TM	Washoe PH	WSO203	550	1	1	1	1	1	1	1
Sierra	TM	Washoe PH	WSO204	550	1	1	1	1	1	1	1
Sierra	TM	West 7th Street	WST1	550	231	231	233	234	237	238	239
Sierra	TM	West 7th Street	WST2	550	250	314	318	321	325	344	363
Sierra	CAR	West Tonopah	WTP1201	550	137	259	260	262	265	297	329
Sierra	CAR	West Tonopah	WTP1202	230	68	69	70	70	71	72	73
Sierra	CAR	West Tonopah	WTP1203	550	91	93	94	94	95	96	97
Sierra	FF	Westside^	WES1211	550	229	229	230	231	234	235	236
Sierra	FF	Westside^	WES1212	550	138	140	141	142	143	145	146
Sierra	FF	Westside^	WES1213	550	86	86	86	87	88	88	89
Sierra	TM	Wheeler	WLR2	475	192	198	205	211	219	226	233
Sierra	EAST	Winnemucca	WIN201	550	223	226	228	230	233	235	237
Sierra	EAST	Winnemucca	WIN202	550	1	1	1	1	1	1	1
Sierra	EAST	Winnemucca	WIN205	550	172	175	178	180	183	186	188
Sierra	EAST	Winnemucca	WIN206	550	139	139	140	141	142	143	144
Sierra	EAST	Winnemucca	WIN701	175	41	42	43	43	43	44	45

All values in amps

DRP UPDATE-4

1. EXHIBIT A SCOPE OF WORK AND SPECIFICATIONS

A.1 ADDITIONAL DEFINITIONS

In addition to the terms defined elsewhere in this Contract, the capitalized terms below shall apply to this Contract and have the following definitions:

1. **Achievable Potential** means a subset of Economic Potential that accounts for real-world constraints, including market and programmatic barriers, supply-chain capabilities, federal and state policy, the impact of existing and future codes and standards, and the rate at which customers could realistically adopt measures, technologies, Programs, or Services.

2. **Adoption Forecast** means a forecast over the Period of Interest of the growth of DER deployment for each DER Category that can be expressed in units (of measures or technologies), kW, and kWh impacts over time in order derive the impacts of various DER adoption scenarios on distribution and system load shapes that allows a forecast of the impacts to the physical electrical grid. Adoption Forecast scenarios use the same assumptions as Achievable Potential scenarios.

3. **BDR means Behavioral Demand Response** which refers to the use of customer messaging—oftentimes in combination with education, gamification, or emergency notifications—to induce customer behavior that changes load shapes.

4. **BESS** means Battery Energy Storage System; one example of Distributed Energy Storage.

5. **Business as Usual Potential** or **BAU Potential** which is a set of Achievable Potential and Adoption Forecast scenarios that could be expected to occur due to likely political, economic, social, and technological environments in the absence of future Company Programs and Services. BAU should consider the impact of the current state of Company DSM and DER Programs and Services.

6. **Connectivity Model** means a database and model of the physical electric distribution grid that includes all major electrical components (*e.g.* conductors, transformers, switches, meters, etc.) and shows how those components are connected to each other.

7. **CVR means Conservation Voltage Reduction** which is the intentional lowering of voltage on the transmission and distribution systems to provide customer voltages in the lower end of the acceptable range, with the goal of achieving energy and demand reductions for customers and the electric system.

8. **DER Aggregation Layer Model** means the layered hierarchical nature of the defined DER Aggregation Points and how multiple DER Aggregation Points at the same level, or Tier, are aggregated at higher tiers to determine the upstream impact of DER adoption or grid services dispatch.

9. **DER Aggregation Point** means a node in the distribution system topology in alignment with the Connectivity Model behind which all downstream DER Grid Points will be aggregated as:

    Tier 1. Service Panel – refers to all DERs on a single customer's service panel.

    Tier 2. Service Transformer – refers to all DERs on the secondary side of a single-phase service transformer.

    Tier 3. Phase – refers to all single-phase DERs on each phase of each feeder.

Tier 4. Feeder - refers to all DERs on a specific single feeder connected to a bus on the low-voltage side of a medium-power transformer or paralleled transformers located in a substation.

Tier 5. Substation – refers to all DERs on all feeders connected to the low-voltage side of all medium power transformers located in a substation.

Tier 6. Zone – refers to two or more adjacent substations (*e.g.* Village and Beltway Substations) with tie points on the distribution system.

10. **DER Grid Point** means a specific DER location within the distribution network.

11. **DR means Demand Response** which refers to a wide range of methods to modify load shapes using Direct Load Control, Price-based Demand Response, and Behavioral Demand Response.

12. **DSM means Demand Side Management** which refers to the Distributed Energy Resource categories of Energy Efficiency and Demand Response.

13. **DER Analytics Toolset ("Toolset")** means Distributed Energy Resource Analytics Toolset; a model, system, or software, including necessary integrations and processes. The Toolset could be an "off the shelf" commercially-available software, customized software, or customized model.

14. **DLC means Direct Load Control** which is a form of Demand Response in which an actor such as a utility or aggregator sends operational control signals directly to DER devices or their controllers. It can include residential and commercial air conditioner load management via communicating thermostats or load control switches. It can include software or hardware-based control of demand-responsive loads such as: EVs or EV charging equipment, energy storage, residential grid-interactive appliances, lighting, refrigeration, and agricultural and industrial loads. It can include control of DG and DES for load building, or Fast DR resources for ancillary services.

15. **DER means Distributed Energy Resource** which refers to technology or measures that reduce or increase load or generate electricity from a renewable source and can be included within one of the following DER categories: Energy Efficiency, Distributed Energy Storage, Electric Vehicles, Demand Response, and Distributed Generation.

16. **DES means Distributed Energy Storage** which refers to a system that stores electric or thermal energy, is located at the Grid Edge, and can include Battery Energy Storage Systems, grid-interactive water heaters, and other storage technologies.

17. **DG means Distributed Generation** which refers to a system that generates electricity from a renewable source, is located at the Grid Edge, and can include solar photovoltaic, wind, water, geothermal, and other renewable generation systems.

18. **DRP means Distributed Resources Plan** which is the plan required by Nevada Revised Statutes ("NRS") Section 704.741(4) that is part of the Company's Integrated Resource Plan ("IRP").

19. **Economic Potential** means a subset of the Technical Potential which accounts for the cost-effectiveness of DER deployment.

20. **EV means Electric Vehicle** which refers to residential, commercial, or fleet light-duty, medium-duty, or heavy-duty electric vehicles.

21. **EE means Energy Efficiency** which refers to technology or measures that reduce the energy consumption of a device, building, or service without reducing unit output, comfort, or service levels. In the context of an EE Program, these types of programs could include, but are not limited to, residential and commercial energy education programs, incentive programs, rebates, installation of energy-efficient products, in-person or online building energy assessments, and paper or online reports programs.

22. **Fast DR Resources** means Demand Response resources that use Flexible Loads, DG, or DES to provide ancillary services such as voltage support and secondary or tertiary frequency regulation, and that can respond to Direct Load Control signals in less than 5 minutes.

23. **Flexible Load** means a type of load used strategically to increase, decrease, or shift electric demand or usage to shape the load curve in real-time.

24. **Grid Edge** means on or adjacent to a customer's property and most often located on the customer side of the utility revenue meter, but can also include front-of-the meter installations for Company owned or managed DER assets deployed in the context of a Company DER program or service.

25. **kW** means Kilowatt.

26. **kWh** means Kilowatt-Hour.

27. **Large Commercial/Industrial/Institutional** customer class means manufacturing, industrial, large office, large retail, and government/institutional.

28. **LNBA means Locational Net Benefit Analysis** which is a cost-benefit analysis of Distributed Energy Resources that incorporates location-specific net benefits to the electric grid.

29. **Low Income** has the same meaning as "Low-income household" in NRS 704.78347.

30. **Managed Potential** means a set of Achievable Potential and Adoption Forecast scenarios which considers the effects of future proposed Company DSM and DER Programs and Services. Managed Potential changes the trajectory of and modifies likely BAU scenarios.

31. **MW** means Megawatt.

32. **MWh** means Megawatt-Hour.

33. **MVA** means Mega-Volt-Ampere.

34. **MVAR** means Mega-Volt-Ampere-Reactive.

35. **NEB means Non-Energy Benefit** which is any quantifiable benefit associated with or through a service provided by a DER other than a benefit associated with the reduced need for energy to be provided from centralized utility-scale generation production, energy procurement, or energy import via transmission lines.

36. **NSPM for EE** means the **National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources**.

37. **NSPM for DERs** means the August 2020 **National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources** (available at the website: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/).

38. **NTRC means Non-Energy Benefit Total Resource Cost** which refers to a jurisdictional specific Total Resource Cost test in Nevada that includes Non-Energy Benefits adders of 10% for commercial customer programs, 15% for residential customer programs, and 25% for the low-income customer programs.

39. **NWA means Non-Wires Alternative** which is a solution to an identified constraint on the utility's electric grid that may include, without limitation, the deployment of a DER or suite of DERs. The Company presently accomplishes its NWA analysis through use of an internally-developed MS Excel-based NWA Screening Analysis Tool.

40. **Participant Cost Test** means a measure of the quantifiable costs and benefits to a customer due to participation in a DER program in alignment with the NSPM for DERs and NSPM for EE.

41. **Period of Interest** means 2025 through 2044.

42. **PBDR means Price-based Demand Response** which refers to the use of price signals in time-varying or dynamic rates to induce customer behavior that changes load shapes. PBDR can include, but is not limited to, Time of Use, Peak Time Rebate, Critical Peak Pricing, and Real Time Pricing rates.

43. **Programs** means a Company managed effort to deploy either specific or bundled DER measures, technologies, or Services to customers with goals and budgets that are generally approved by regulators in an appropriate regulatory filing.

44. **PV** means Photovoltaic.

45. **PWRR means Present Worth of Revenue Requirement** which is a financial calculation that determines the net present value of the total future revenue required to be collected to cover the costs associated with a project.

46. **Residential** customer class means single-family dwellings and single-family dwellings in a multi-unit complex who receive residential service from the utility.

47. **Rate Impact Measure Test** means a measure of the effect of a DER program on customer bills or rates due to changes in utility revenue and operating costs in alignment with the NSPM for DERs and NSPM for EE.

48. **Services** means the provision of electricity, storage, EV charging, bill management, online tools, and other customer services generally accompanied by a rate, tariff, tariff rider, and/or customer agreement.

49. **Small Commercial/General Business** customer class means grocery/retail, small office, restaurant, lodging, and entertainment who receive non-residential service from the utility.

50. **Societal Cost Test** refers to a measure of the change in the total resource costs to society as a whole rather than to only the utility and its customers that is in alignment with the NSPM for DERs and NSPM for EE.

51. **Technical Potential** is the theoretical maximum amount of DER adoption and associated impacts on load magnitude and shape within a given spatial area without consideration of cost-effectiveness, market barriers, and the willingness of users to adopt a measure, program, or technology expressed in units, kW, and kWh over time. Technical Potential considers the resource potential of renewable energy and weather patterns within the given spatial area.

52. **TRC means Total Resource Cost** which refers to a standard practice test that calculates the net benefits ratio of a DER program from a societal perspective and includes both participant and utility costs in alignment with the NSPM for DERs and NSPM for EE.

53. **Underserved Communities** has the same meaning as "Historically underserved community" in NRS 704.78343.

54. **Utility Cost Test** means a measure of the net costs of a DER program as a resource option based upon the costs incurred by the utility, excluding the net costs incurred by the participant in alignment with the NSPM for DERs and NSPM for EE.

A.2 SCOPE OF WORK

Functional Requirements

DER Market Potential Study ("MPS") Requirements

The Consultant shall provide a MPS covering the Period of Interest that meets the following requirements:

1. The Consultant shall use the DER Analytics Toolset to the greatest extent possible to create a MPS and DER Adoption Forecast for use in Company's June 1, 2024 IRP ("2024 IRP") filing.
2. The Consultant shall research, gather, and organize baseline information about the current state of DER adoption in the Company's service territory. The Consultant shall review and consider use of data sets available from the Company (*e.g.,* results of recent in-home and online energy audits and assessments, interconnection data, Program data, etc.) and reputable third-party market research firms. If such data is insufficient, the Consultant shall perform primary market research to fill identified gaps required to better characterize DER adoption and residential and commercial end-use loads. For sampled data, the Consultant shall use methods that ensure interval estimates exceed 90% confidence levels.
3. The Consultant shall recommend and provide clear descriptions and categorization methods for DER measures, technologies, Programs, and Services within the major DER categories of EE, DR, DG, DES, EV, and the DR subcategories of DLC, PRDR, and BDR. Consultant shall use current industry practices and anticipated industry developments as guides for how best to categorize measures and technologies.
4. The Consultant shall recommend and provide a customer segmentation methodology that provides useful insights into current state and future state of DER adoption. The customer segmentation methodology should allow characterization and examination of DER adoption among Low Income residential customers and Small Commercial/General Business in Underserved Communities. The customer segmentation method should allow characterization and examination of DER adoption across the following customer classes: Residential, Small Commercial/General Business, Large Commercial/Industrial/Institutional, as defined in Section A.1.
5. The Consultant shall characterize current state and future state DER adoption by electricity grid location using NV Energy's Connectivity Model in order to generate the load impacts of DER

adoption at each Tier of the DER Aggregation Layer Model, or an equivalent level based upon discussion and agreement with the Company.

6. The Consultant shall derive DER Adoption Forecast scenarios during the Period of Interest by first determining Technical Potential, followed by determination of Economic Potential scenarios, and then finally Achievable Potential scenarios including BAU Potential and Managed Potential, as defined in Section A.1.
7. The Consultant shall recommend and provide a series of BAU Potential scenarios that are used to create a probability impact matrix.
8. The Consultant shall recommend and identify which of the higher probability and/or higher impact BAU Potential scenarios should be considered for use in developing portfolios of DER Programs and Services.
9. The Consultant shall develop and recommend future portfolios of DER Programs and Services in collaboration with the Company that focus on carbon reduction strategies that optimize the grid impacts of and grid integration of DERs in order to create a smaller set of Managed Potential scenarios to guide proposals for the 2024 IRP filing.
10. The Consultant shall ensure that the range of DER Programs and Services considered is comprehensive across options that are commercial today as well as considering enabling technologies which evidence suggests will become commercially available during the Period of Interest.
11. The Consultant shall endeavor to ensure that all research, analysis, and methods can be demonstrated to be consistent with recognized industry practices to aid in ensuring reduced regulatory and stakeholder risk as the Company defends its proposals in its 2024 IRP filing.
12. The Consultant shall provide a special section within the results of the MPS that highlights the impacts of BAU Potential and Managed Potential scenarios on Low Income residential customers and Small Commercial/General Businesses serving Underserved Communities during the Period of Interest.
13. The Consultant shall provide a special section within the results of the MPS that highlights the impacts of DSM within the BAU Potential and Managed Potential scenarios.

DER Analytics Toolset Requirements

The Consultant shall provide a DER Analytics Toolset ("Toolset") with DER forecasting and valuation capabilities that meets the following requirements:

DER Forecasting Requirements

14. The Toolset shall have a user-friendly interface and intuitive utilization that allows it to be learned and mastered by Company personnel with a reasonable amount of training.
15. The Toolset shall produce Adoption Forecast scenarios for BAU Potential and Managed Potential with hourly demand and energy forecasts for each DER category for each year of the Period of Interest.
16. The Toolset shall contain a DER load impact and generation curve library or engine for all significant DER measures and technologies with programmable characteristics and assumptions.
17. The Toolset shall contain the flexibility to add new DER measure and technology types.
18. The Toolset shall allow user-defined multi-scenario sensitivity analysis including, but not limited to, the capability to:

a. adjust, eliminate, or add Programs and Services;
b. adjust political, economic, social, and technological assumptions;
c. define and analyze results by customer segments and rate classes;
d. define and analyze results by DER categories and subcategories; and
e. analyze results for Low Income and Small Commercial/General Businesses serving Underserved Communities.

19. The Toolset shall produce an Adoption Forecast for each type of DER considering available historical data and DER growth models for a given spatial location.
20. The Toolset shall produce for each DER type its Technical Potential, Economic Potential, and Achievable Potential for a given spatial location in the context of DER Adoption Forecasts for BAU Potential and Managed Potential scenarios.
21. The Toolset shall be capable of producing locational forecast data for each DER type at each DER Aggregation Layer Model Tier or an equivalent level based upon discussion and agreement with the Company.
22. The Toolset shall allow alignment with and adjustment of imported forecasts from other systems (see Technical Requirements below) for the system-level forecast and individual distribution feeder forecasts.
23. The Toolset shall be able to estimate or assign the probability of occurrence of BAU Potential DER Adoption Forecasts.
24. The Toolset shall be able to estimate the statistical error of and determine confidence intervals/bands for load and generation forecast curves and load impact curve for DER measures and technologies across the Period of Interest.
25. The Toolset shall be capable of exporting 8,760 DER load impact curves at the system level for Managed Potential forecast scenarios in order to modify the long-term system level load forecast determined by the Company's long-term load forecasting group.

DER Valuation Requirements

26. The Toolset shall determine the cost-effectiveness of the Company's DER programs and program portfolio during program planning and post-implementation evaluation.
27. The Toolset shall calculate the five standard practice cost-effectiveness tests adopted by the industry, *i.e.*, the Total Resource Cost Test, the Rate Impact Measure Test, the Utility Cost Test, the Participant Cost Test, and the Societal Cost Test.
28. The Toolset shall calculate energy benefits and NEBs, including but not limited to, avoided energy costs, avoided generation capacity costs, avoided transmission and distribution capacity costs, bill reductions, avoided greenhouse gas costs, conservation adders or externalities, indirect fuel benefits, and rebates, for the Company, host customer, and society at both the locational and system levels. Consultant shall refer to Table DSM-18 in the Company's most recent DSM Update Report filed with the Public Utilities Commission of Nevada ("Commission") in Docket No. 22-07004 available at the Commission website (https://puc.nv.gov) to obtain which benefits are currently included in the Company's standard practice cost-effectiveness tests.
29. The Toolset shall calculate costs, including, implementation costs, direct customers costs, utility program administration and measurement and verification costs, rebates, and reduced sales, for the Company, host customer, and society at both the locational and system levels. Consultant shall refer to Table DSM-18 in the Company's most recent DSM Update Report filed with the

Commission in Docket No. 22-07004 available at the Commission website (https://puc.nv.gov) to obtain which costs are currently included in the Company's standard practice cost-effectiveness tests.

30. The Toolset shall be capable of incorporating and valuing the potential benefits and costs noted in the NSPM for DERs that are not currently included in the Company's standard practice cost-effectiveness tests that the Consultant recommends are commonly used in the industry and are more likely to be readily quantifiable for the Company with respect to its DSM and DER Programs and NWA analysis.
31. The Toolset shall provide a flexible platform to evaluate the cost-effectiveness of Fast DR Resources, DES, and other types of DERs taking into consideration the stacking of multiple value streams.
32. The Toolset shall facilitate appropriate calculation of locational costs and benefits so that the Company may appropriately incorporate these into DSM and DER Program cost-effectiveness and LNBA analyses.
33. The Toolset shall calculate the cost-effectiveness of DG (*e.g.*, rooftop solar PV) and BESS in a harmonized fashion, *i.e.*, using appropriate and consistent assumptions across DER valuations, appropriately taking into consideration locational costs and benefits and the level of dispatchability and/or achievable coordination of these assets with grid operations.
34. The Toolset shall be capable of identifying and compensating (*i.e.*, appropriately adjusting cost and benefit streams) for interactive effects among DERs deployed in a portfolio of DER Programs and Services.
35. The Toolset shall incorporate stochastic modeling related to input assumptions (*e.g.*, energy price forecast) and output reporting for probabilistic distribution simulation and risk assessment.
36. The Toolset shall easily facilitate automated scenario analyses that incorporate and analyze changes in energy (*e.g.*, energy and demand impacts of measures) and financial parameter assumptions (*e.g.*, discount rate, load dependent line loss factors, avoided costs, etc.). Key assumption parameters should be treated as probabilistic inputs where required.
37. The Toolset shall allow Program and measure level inputs (*e.g.*, administration costs, implementation costs, participant incremental costs, incentives and rebates paid to participants, demand savings, and energy savings) to be handled either as deterministic inputs or as probabilistic inputs that follow certain commonly-used distributions (*e.g.*, triangular distribution, normal distribution, etc.). Monte Carlo simulations can be executed to obtain the probabilistic outcome of the cost effectiveness tests at both the individual program level and the program portfolio level.
38. The Toolset shall calculate the insurance option value (or extrinsic value) of dispatchable DERs (*e.g.*, DR Program option value) and appropriately incorporate the benefit into the standard practice test outputs. The valuation methodology shall allow for stochastic simulation of the forecast variables (or risk factors such as energy prices) and be able to replicate the operational strategies and opportunities of the program technologies.
39. The Toolset shall provide functionality to incorporate nodal pricing data into the assessment of the value of DSM, DER and NWA measures.

Results Output and Visualization Requirements

40. The Toolset shall provide output results in customizable, common spreadsheet or database formats.
41. The Toolset shall provide output results in customizable reports and graphs, including loading and generation curves for each of the DER categories across each DER Aggregation Layer Model Tier.

42. The Toolset shall provide output results that can be visualized in customizable, common mapping formats (*e.g.*, heat maps).

Service Requirements

The Consultant shall:

43. Build, factory test, deliver, configure, customize, and integrate the Toolset according to agreed-upon licensing terms and implementation and testing schedules.
44. Work with the Company to populate the Toolset with required datasets and perform system integration testing and user acceptance testing.
45. Provide maintenance and support under an agreed-upon software maintenance and support agreement.
46. Deliver a version of the valuation of DER Programs in the Managed Potential scenarios proposed to the Commission that accommodates the Company's current specific assumptions and cost effectiveness test definitions that can be calibrated to produce the cost-effectiveness test results of the Company's existing PortfolioPro or Ace Guru™ Models under controlled benchmarking comparisons (*e.g.*, when no extrinsic/option values or other NEBs are accounted for in order to see the before and after impacts of incorporating new benefit types).
47. Provide detailed business process documentation and user guides showing how the Toolset is used to produce the various potential scenarios and Adoption Forecasts and associated reports and visualizations.
48. Provide detailed business process documentation and user guides showing how the Toolset is used to produce DER Program valuations and how to interpret the input assumptions and output results.
49. Provide a demonstration of the Toolset solution for the Company following the Company's technical evaluation if the solution is deemed technically acceptable.
50. Provide hands-on training workshops for Company employees in the detailed use and maintenance of the Toolset.
51. Conduct or assist with stakeholder workshops (Commission staff and Nevada Bureau of Consumer Protection) designed to inform and education stakeholders about the theories and approaches of DER Program evaluation, option value calculations, NEBs, and effective use of the Toolset.
52. Design a cost-effective strategy to enable stakeholders (Commission staff and Nevada Bureau of Consumer Protection) to develop a level of familiarity and working knowledge of the Toolset that leads to confidence in its capability to produce meaningful and accurate results in a manner that can be easily understood by stakeholders.
53. Provide ad-hoc forecasting and valuation consulting services to Company users when requested.
54. Provide expert witnesses as required to support the results of the MPS and DER Adoption Forecast in regulatory filings such as the Company's 2024 IRP.

Technical Requirements

55. The Toolset shall be able to accommodate the data exchange processes identified in the below table.

System	Data Export from Toolset	Data Import to Toolset
TAM	DER adoption forecast by feeder	Feeder load forecasts-
PI	-	Feeder headend historical load data
MDMS	-	15-min interval data from utility meters at customer premise
GIS	-	Connectivity Model
RRA forecast system	8,760 load impact forecasts	8,760 long-term load forecast
Synergi	DER adoption forecast by feeder	-
PowerClerk	-	Current state installed DG/ES/EV
DRMS		Current state DR Program enrollments

TAM means Task-Action-Management and is an NV Energy internally-developed MS Excel and MS Access based system used to track new load additions to the distribution system and generate distribution feeder and substation transformer load forecasts.

PI historically meant Plant Information, which is the system by OSIsoft that captures loading data on the Company's transmission and distribution systems.

MDMS means the Company's Meter Data Management System which is the system of record for historical 15-min interval data from smart meters along with billing determinant information.

GIS means the Company's Geographic Information System that maps the overhead and underground transmission and distribution systems.

RRA means the Company's Rates and Regulatory Affairs organization within which the Load Forecasting department produces system-level load forecast information.

Synergi means Synergi Electric which is the electrical simulation and load flow analysis software used by the Company provided by DNV.

PowerClerk is an external platform by Clean Power Research where the Company's customers submit their applications related to PV generation, battery storage, electrical vehicle chargers.

56. Consultant's solution shall, at a minimum, have the capability to integrate with Company systems via SFTP (data protocols) and import and export common data file formats such as .CSV file format. The Company can accommodate other integration methods and file formats as defined and agreed upon.
57. Consultant's solution shall have the capability of being operational and available to the Company at least 99.5% of the time in any calendar month, including planned downtime.
58. Consultant's solution shall provide response time for system data display and screen refresh of no more than 2-seconds.
59. Consultant's solution shall have built-in weather integration.
60. Consultant should consider use of and propose use of, if deemed useful, relevant, or required, the following systems:

    BANNER – this is the Company's billing system and system of record for customer information.

Bidgely Data Sets – these data sets record the results of residential customer online and in-home energy audits, answers to customer online surveys that characterize the energy assets in their home, and monthly energy disaggregation records that represent an estimation of the monthly energy use and cost by end-use load categories.

DSM Central – a historical repository of delivered DSM measures in prior Program implementation years.

Consultant Deliverables

61. The Consultant shall provide the Company a draft report by September 29, 2023 and a final report of the MPS results for the Period of Interest in accordance with the above **DER MPS Requirements** by October 31, 2023.
62. The Consultant shall provide the Company the draft DER Analytics (forecast and valuation) results for the Period of Interest by November 30, 2023 and the final DER Analytics (forecast and valuation) results for the Period of Interest through use of the Toolset in accordance with the above **DER Analytics Toolset Requirements** by December 29, 2023.
63. The Consultant shall provide the Company the **Toolset** and associated documentation for the Company's use on a going-forward basis by March 1, 2024.
64. The Consultant shall specify and provide all data sources, technical assumptions, methodologies, supporting documentation, saturation survey results, and analytical procedures used to support the MPS and the DER Analytics (forecast and valuation) results for all DER categories, subject to appropriate confidentiality requirements.
65. The Consultant shall submit proposals that clearly indicate the commitments by the Consultant to provide ongoing support of the MPS and the DER Analytics (forecast and valuation) results in response to this RFP for a minimum of two years, such commitments to include: a) responding to written and oral data requests, both to Company and external parties in regulatory proceedings; b) attending required meetings, conference calls, etc. to support the MPS and DER Analytics (forecasting and valuation) results, including technical aspects of any surveys, final studies, and evaluations; and c) providing expert written and oral testimony as required before the Commission that supports the MPS and DER Analytics (forecasting and valuation) results and Toolset.

Optional NWA Solution Functional Requirements

In addition to the requirements for the DER Analytics Toolset and Potential Study, the Company is also seeking optional pricing for the inclusion of a solution that would provide NWA analysis capabilities either within or separate from the Toolset. The NWA solution shall:

1. Be able to accept and use information specific to Company transmission and distribution ("T&D") traditional capital wired projects including the project name, business unit (Nevada Power Company or Sierra Pacific Power Company), Link Code (two- or three-digit alphanumeric code), priority (whole number one through six), cost estimate (total and annual cash flow), investment reason (text field), planning in-service date (mm/dd/yyyy format), base year (yyyy format), constraint description (text field) and proposed solution (text field).
2. Allow display of diagrams and maps (*e.g.*, .jpeg or .pdf format) depicting substation one-lines, T&D system one-lines, any diagrams or maps associated with proposed Company traditional capital wired projects, local area geographic maps, aerial maps, or land use maps.
3. Allow input of 15-minute MW and MVAR load data for a T&D system element (*e.g.,* transmission line, distribution feeder, substation transformer) for a full year with variable beginning and end

dates and with the date (mm/dd/yyyy format), hour (0 through 23), time (12-hr format) for each 15-minute data point.

4. Calculate the MVA for each 15-minute MW and MVAR load data point, determine the maximum (peak) MVA for the base year of load data, and provide the date and time of that maximum.
5. Allow input of the net annual peak load forecast in MVA for a T&D system element for a period of 10 years beyond the base year of the load data.
6. Calculate the MVA for each 15-minute load data point for a period of 10 years beyond the base year of the load data adjusted based upon the net annual peak load forecast in MVA for a T&D system element as compared to the peak MVA for that element in the base year.
7. Allow input of the asset limit (in most cases, the continuous rating) in MVA of a subject T&D system element.
8. Display a multi-colored line graph of the daily (24-hour) 15-minute loading curve of a T&D system element for the base year and the subsequent 10 years with the asset limit also shown on the graph. The day charted (*i.e.*, the "chart day") shall be a selectable input by the user.
9. Determine the peak overload in MVA (*i.e.*, the difference between the peak loading and the asset limit), the total energy need in MWh (*i.e.*, the area under the net loading curve bordered by the asset limit line), the overload period length in hours with appropriate quarter hours, the overload start time (12-hr format), and the overload stop time (12-hr format) for each chart day with the year (base year and the subsequent 10 years) being selectable by the user.
10. Display the peak overload in MVA and total energy need in MWh in a multi-colored bar graph showing the base year and the subsequent 10 years for each chart day selected by the user and a numeric table showing the same information.
11. Determine the estimated number of days that an overload will occur in each year for the base year and the subsequent 10 years and identify the day of the year with the highest total energy need in MWh in each of those years.
12. Perform a Present Worth of Revenue Requirement ("PWRR") calculation for the traditional wired project installed in its planned in-service year and the installation of the project deferred to each year beyond that year within the 10-year period of the analysis.
13. Allow user input of pertinent financial data necessary to perform all PWRR calculations, including investment tax credits.
14. Provide the traditional wired project deferral value and cumulative deferral value for each year within the 10-year period of the analysis.
15. Perform a LNBA PWRR calculation for each year of the analysis to determine the minimum cost NWA (DER) portfolio solution that minimally eliminates the maximum forecasted MVA and MWh overload including both DER costs and benefits, compare that optimized minimum PWRR value against the traditional wired project deferral value for each year, and determine if the net cost of the NWA (DER) portfolio solution is greater or less than the savings achieved from deferring the traditional wired project.
16. Be capable of user selection or deselection of any or all of the DER benefits in the LNBA.
17. Allow user input of Company cost data necessary to quantify the DER benefits used in the LNBA.
18. Allow user input of any total interconnection/integration cost for implementation of an NWA (DER) portfolio solution to be included in any PWRR calculations.

19. Allow users to model multiple DER and CVR portfolios of varying magnitude within the context of a specific NWA solution consistent with identified Technical, Economic, and Achievable Potential scenarios for DERs in the grid locations associated with or impacted by the NWA and traditional wired solution.
20. Allow for additional DER technologies, both in front of the meter or behind the meter, to be added in any potential NWA (DER) portfolio solution.
21. Value the costs and benefits of NWA portfolio solutions using the DER Analytics Toolset valuation capabilities and methodologies and harmonize the valuation methodologies supporting calculation of the PWRR for NWA (DER) portfolio solutions.
22. Display a cost table showing each DER technology used in a NWA (DER) portfolio solution including the capacity, price per unit, total cost per DER technology, and total estimated NWA (DER) portfolio solution cost.
23. Display in tabular form the amount of EE, DR, CVR, PV, and BESS capacity in the optimized minimum cost NWA (DER) portfolio solution per year of the analysis period.
24. Allow user input of the estimated existing amount of DR capacity on a T&D system element which will be added to any incremental amount of DR capacity determined in an optimized NWA (DER) portfolio solution.
25. Be capable of modeling preloaded DR MW reduction by hour.
26. Allow user input of the hours that DR can be used in an NWA (DER) portfolio solution, the MW reduction by hour for DR, and user selection of the user defined MW reduction or the preloaded MW reduction by hour.
27. Allow user input of the number of DR events that can be modeled per year.
28. Allow user input of the number distribution feeders, substation transformers, distribution line capacitors involved with CVR to determine the estimated cost to implement that DER technology.
29. Allow user input of the CVR start and stop time and estimated number of events per year.
30. Be capable of modeling the charging curve of any BESS used in an NWA (DER) portfolio solution based upon user defined charging start and stop hours to ensure that such charging during off peak hours does not cause the load curve to exceed the asset limit capacity.
31. Display BESS charging MW and MWH.
32. Allow user input of BESS round trip efficiency and cycles per year.
33. Model the effect of BESS parasitic load.
34. Display on a multi-colored line graph the unaffected load curve, asset limit, individual curves illustrating the MW and MWH reduction achieved by each DER technology used in an optimized NWA (DER) portfolio solution (down to the asset limit), and any BESS charging curve for any user selected analysis day.

A.3 Performance, Training, Coordination

1. Place of Delivery and Performance. The Site is within Company's service territory which includes the following cities and counties in Nevada: Clark County, Washoe County, Carson City, Douglas County, Lyon County, Churchill County, and Pershing County. Consultant shall deliver to the Site at its expense all equipment, materials and other goods Consultant shall provide under this Contract.

2. Performance of the Work. Consultant shall (a) diligently and properly perform and complete the Work and its other obligations in accordance with this Contract, and (b) provide and pay for all items and services necessary for the proper execution and completion of the Work, whether temporary or permanent and whether or not incorporated or to be incorporated into the Work, including, all procurement, installation and construction services, all administration, management, training and coordination, all start-up, commissioning and testing services, and all labor, material, construction aids, furnishings, equipment, supplies, insurance, permits, licenses, inspections, storage and transportation, and all other items, facilities and services.

3. Consultant shall perform all work not specifically delineated in this EXHIBIT A or elsewhere in this Contract to the extent necessary to complete the Facility in accordance with all Laws and Prudent Industry Practices. Consultant shall execute the entire Work under this Contract and shall do so in a manner that will enable Consultant to achieve Substantial Completion by the Guaranteed Substantial Completion Date and Final Completion by the Guaranteed Final Completion Date. Consultant shall achieve Substantial Completion by the Guaranteed Substantial Completion Date and shall achieve Final Completion by the Guaranteed Final Completion Date.

4. Professional Standards. Consultant shall perform and complete the Work and its other obligations under this Contract in accordance with all Laws, this Contract and Prudent Industry Practices.

5. Training. Consultant shall develop and implement a program to instruct and train Company's personnel adequately on the use of the Toolset in accordance with the provisions of EXHIBIT A, such training to be completed by April 1, 2024.

6. Coordination. Consultant shall coordinate the Work through Company's Project Manager and give Company advance written notice of when and where it will perform the Work in order to avoid confusion and delay.

7. No Interference. Consultant will not commit or permit any act that would interfere with Company's, or any other Consultant's, activities on or near the Site. Consultant will at all times comply with Company's instructions regarding the coordination of the Work with other activities at the Site.

A.4 Subcontractor Information

Below are the Subcontractors that will be utilized in the performance of this Work.

Subcontractor Name	Description of the Work

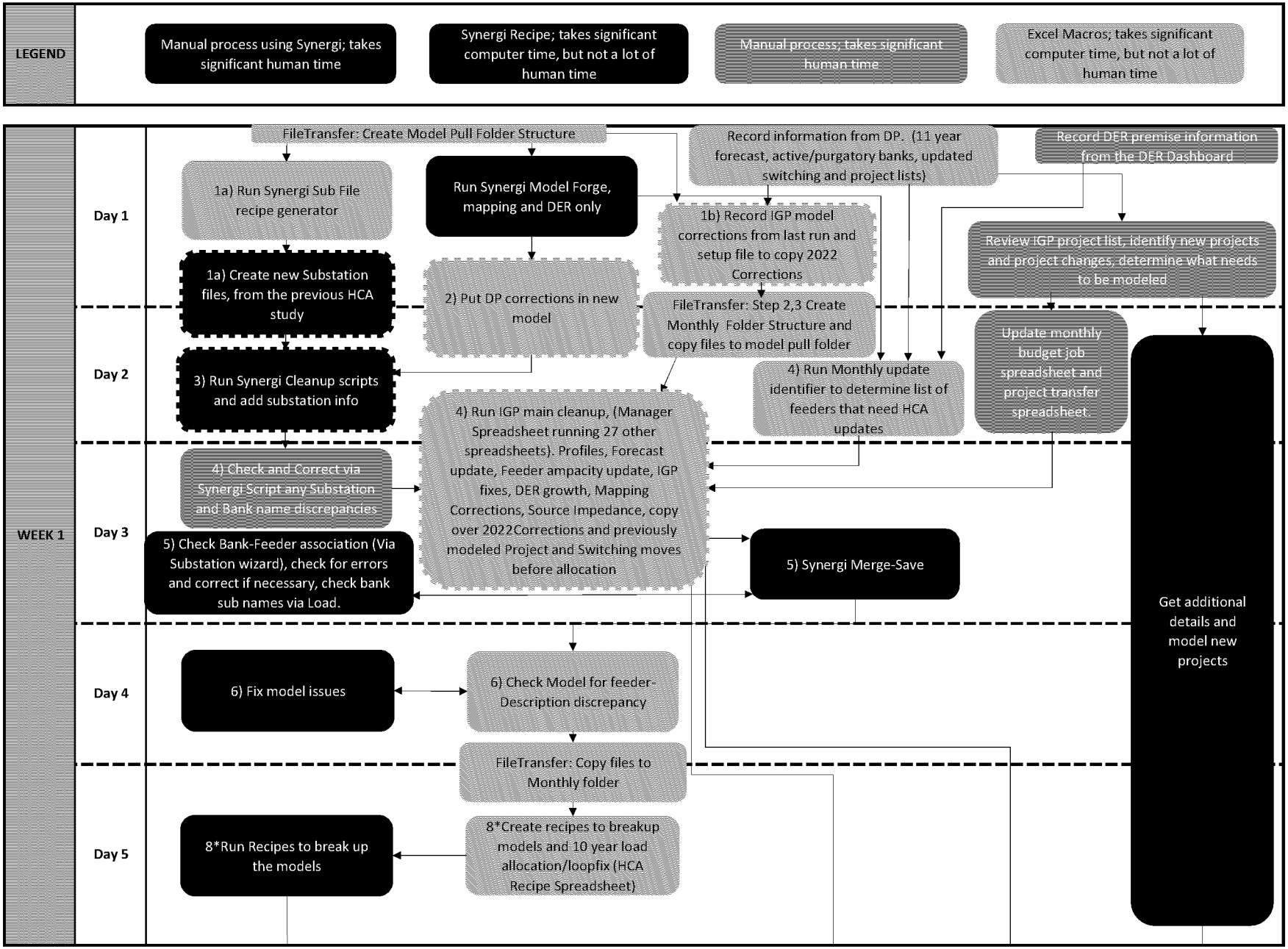
A.5 Key Personnel

Provide names, titles and contact information for the persons who are deemed Consultant's key personnel, whose efforts are essential to the successful completion of the Contract.

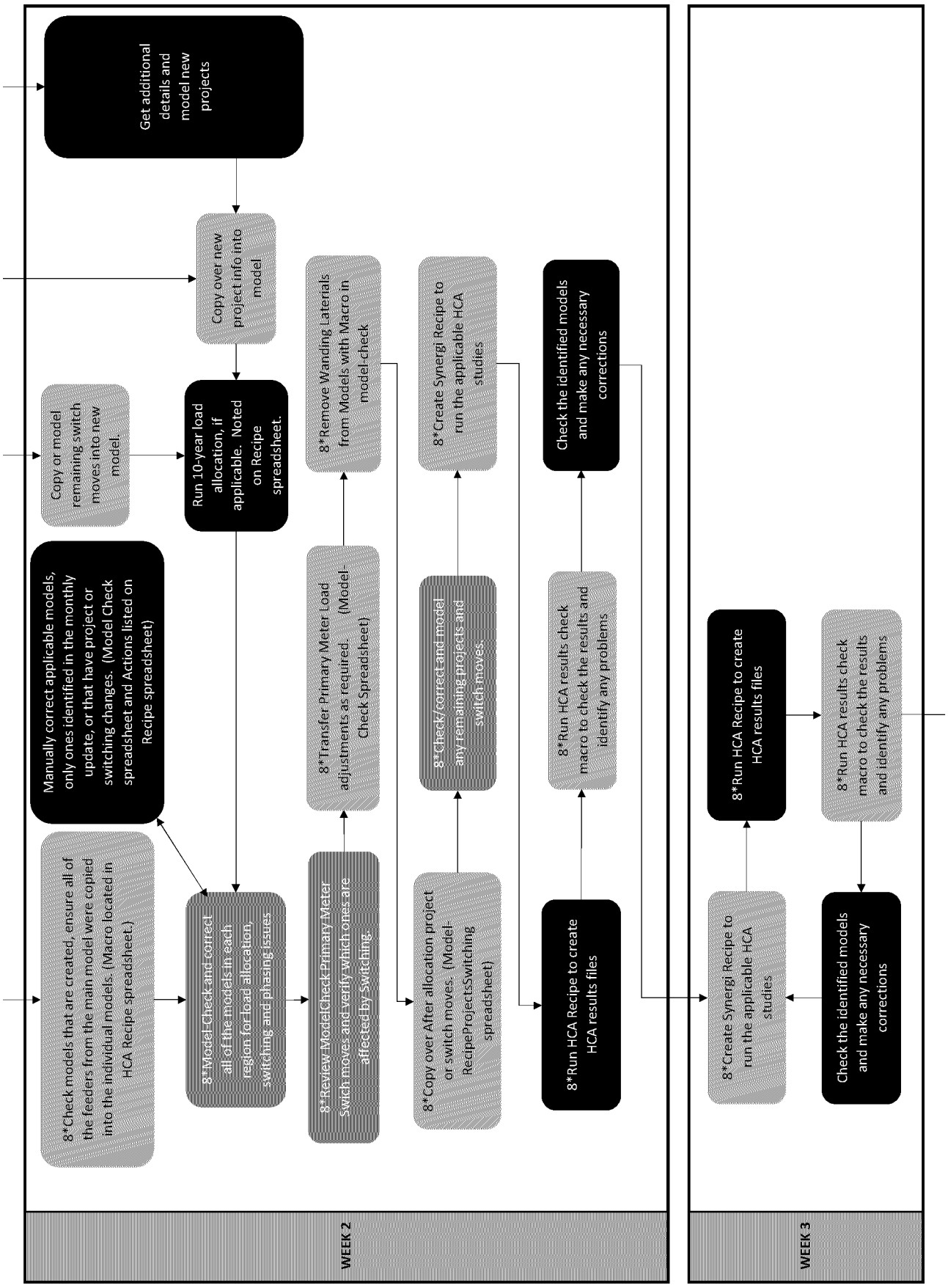
Name	Contact Information	Description of Role in Project

DRP UPDATE-5

NV ENERGY HCA MONTHLY UPDATE INTERNAL PROCESS FLOWCHART

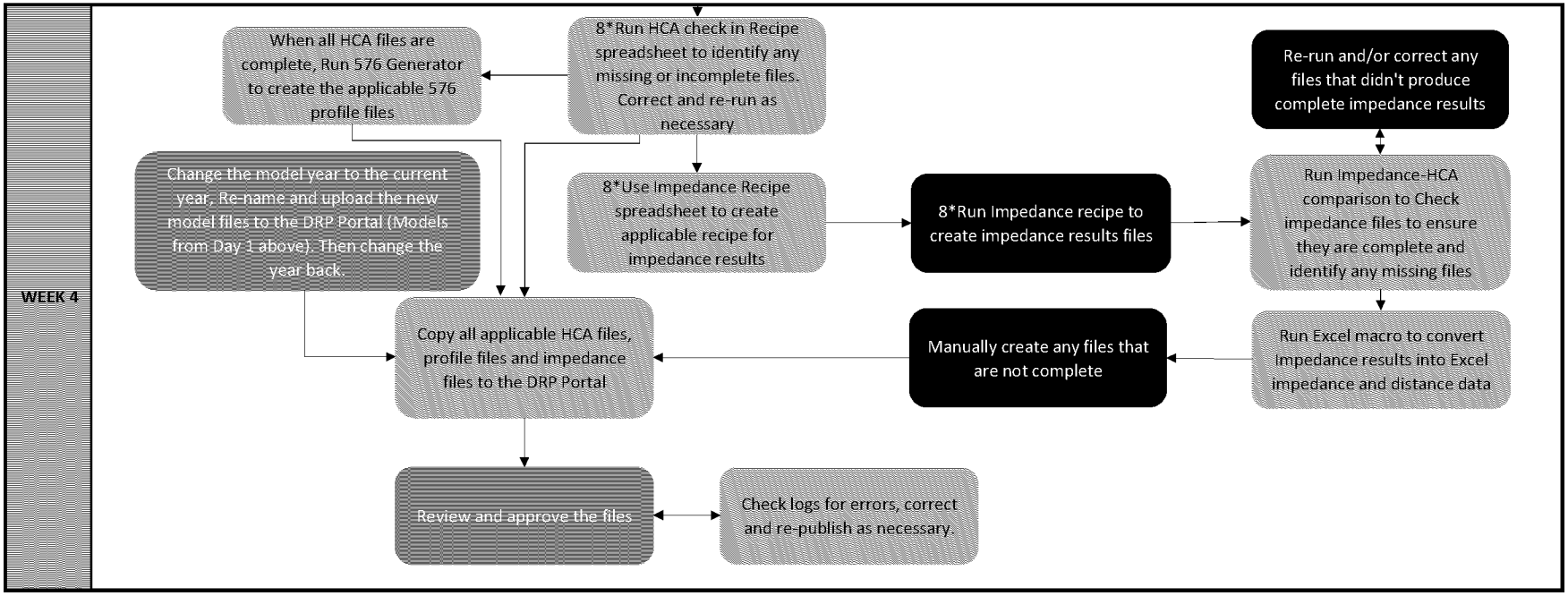


NV ENERGY HCA MONTHLY UPDATE INTERNAL PROCESS FLOWCHART



2

NV ENERGY HCA MONTHLY UPDATE INTERNAL PROCESS FLOWCHART



DER = Distributed Energy Resources
DP = Distribution Planning Department
HCA = Hosting Capacity Analysis
IGP = Integrated Grid Planning Department

DRP UPDATE-6

NV Energy Standard Loading Criteria ("SLC")

SLC Transformers/Feeder Rating	Risk of Overloading (% Load) High
Transformers - 14 MVA and above	≥ 90%
Feeders - 600 amps and below	≥ 90%

SLC Transformers/Feeder Rating	Risk of Overloading (% Load)		
	Low	Moderate	High
Transformers - Below 14 MVA*	80-85%	85-90%	> 90%
Feeders - Above 600 amps	80-85%	85-90%	> 90%

*At the discretion of the Distribution Planning Engineer, substations with 14 MVA transformer and below may be addressed sooner than the SLC threshold warrants.

A staggered approach to initiating new projects based on the SLC will be implemented. Priority will be placed on transformers and feeders that are at the highest risk of overloading. This allows for better allocation of resources and capital to facilities that need solutions due to the higher risk.

Below is the schedule of priority for project initiation by year:

- 2023: High-risk projects
- 2024: Moderate-risk projects and above
- 2025: Low-risk projects and above

DRP UPDATE-7

NV ENERGY
DISTRIBUTED RESOURCES PLAN
WEB PORTAL USER GUIDE

Version 3.2

May 10, 2023

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DISCLAIMER:

While NV Energy makes every effort to ensure the accuracy of the information on its Distributed Resources Plan Web Portal ("DRP Web Portal"), the data provided is for informational purposes only and NV Energy makes no guarantee, expressly or implied, regarding the accuracy, completeness, and/or suitability of the information presented on the DRP Web Portal for any purpose. In no event will NV Energy be responsible for the consequences associated with use of the information. Please refer to NV Energy's Privacy and Usage policies on the DRP Web Portal for complete information regarding its use.

VERSION	ISSUE DATE	COMMENTS
1.0	September 9, 2019	Initial version
1.1	December 20, 2019	Added details of the new data download capabilities
2.0	June 1, 2020	Added details of multiple enhancements to the portal
3.0	June 24, 2021	Revised registration and logon due to transition to Microsoft Authenticator
3.1	September 26, 2022	Revised access screen graphic on page 4
3.2	May 10, 2023	Minor wording changes

Introduction

Acronyms & Definitions

Distributed Energy Resource(s) ("DER" or "DERs") – Distributed generation systems, energy efficiency, energy storage, electric vehicles and demand-response technologies, which can be in front of or behind the meter.

Distributed Resources Plan ("DRP") – Pursuant to Nevada Revised Statutes §704.741(4), the plan required by 2017 Nevada Senate Bill 146 to be filed by NV Energy triennially as part of its Integrated Resource Plan.

Distribution Management System ("DMS") – A collection of applications designed to monitor and control a distribution network efficiently, reliably, and safely.

Feeder – A medium voltage (*e.g.*, 4 kV, 12 kV or 25 kV) line either overhead or underground that provides service from a substation transformer to a low voltage electric system or directly to the customer.

Generation Hosting Capacity ("GHC") – The available incremental Hosting Capacity based upon the Uniform Generation analysis case in the Hosting Capacity Analysis before a thermal, steady-state voltage, or voltage variation limitation is encountered.

GHG – Greenhouse Gas.

Grid Needs Assessment ("GNA") – A summary that includes the constraints on a utility's electric grid and solutions to those constraints. It includes all analysis of non-wires alternatives' suitability to mitigate identified constraints, results of locational net benefit analysis and recommendations for the deployment of utility infrastructure upgrade solutions and non-wires alternative solutions to identified constraints.

Hosting Capacity Analysis ("HCA") – The analysis to determine the amount of Distributed Energy Resources that can be accommodated on a particular feeder section of the distribution system at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

kVA – kilo Volt-Amperes.

Load Hosting Capacity ("LHC") – The available incremental Hosting Capacity based upon the Uniform Load analysis case in the Hosting Capacity Analysis before a thermal, steady-state voltage, or voltage variation limitation is encountered.

Locational Net Benefit Analysis ("LNBA") – A cost benefit analysis of Distributed Energy Resources that incorporates the location-specific net benefits to the electric grid.

Non-Wires Alternative ("NWA") – A solution to an identified constraint(s) on a utility's electric grid that may include the deployment of a Distributed Energy Resource or suite (package) of Distributed Energy Resources.

NPC – Nevada Power Company.

NVE – NV Energy.

OMAG – Operation, Maintenance, Administrative, and General expenses.

Photovoltaic Hosting Capacity ("PHC") – The available incremental Hosting Capacity based upon the Photovoltaic analysis case (focused on the hours of 10:00-16:00) in the Hosting Capacity Analysis before a thermal, steady-state voltage, or voltage variation limitation is encountered.

PV – Photovoltaic.

RPS – Renewable Portfolio Standard.

SPPC – Sierra Pacific Power Company.

T&D – Transmission and distribution.

Overview

In response to 2017 Nevada Senate Bill 146 and the resulting regulations in Nevada Revised Statutes and Nevada Administrative Code, NV Energy developed and filed its first Distributed Resources Plan ("DRP") with the Public Utilities Commission of Nevada on April 1, 2019. Additions to regulation required updates to NV Energy's distribution system Hosting Capacity Analysis ("HCA") to be made publicly available at least bi-annually and NV Energy's corporate website to contain a portal that provides maps and accessible, downloadable electronic data for distribution to the public. To comply with these requirements, NV Energy developed its publicly-accessible DRP Web Portal.

The information on NV Energy's DRP Web Portal can assist developers and vendors seeking information to support quality decisions in siting Distributed Energy Resource ("DER") solutions. The DRP Web Portal provides HCA, Grid Needs Assessment ("GNA"), and Locational Net Benefit Analysis ("LNBA") information for NV Energy's electric distribution system, allowing users to quickly find areas that have constraints, greater ability to incorporate new DER capacity, or enhanced benefit of locating DERs in a given area. NV Energy's electric transmission lines are not shown on the DRP Web Portal maps.

Although some of the data values accessible on the DRP Web Portal may have been updated since the date shown, this User Guide reflects only the type of information and capabilities of the DRP Web Portal available as of the version date shown. This User Guide will be updated when additional information or capabilities have been added to the DRP Web Portal.

NOTE: The data for certain distribution feeders have been redacted from the map views resulting in blank areas on the map where feeders actually exist. Consequently, the HCA, GNA, and LNBA data discussed in this User Guide is not available on the DRP Web Portal for these feeders.

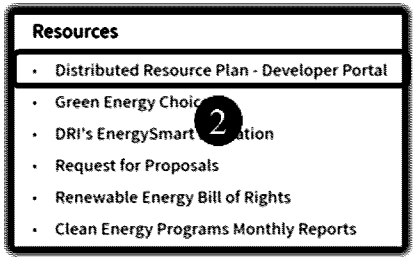
Access and Login Page Information

NOTE: The DRP Web Portal must be accessed through the Microsoft Edge or Google Chrome web browsers.

NV Energy's DRP Web Portal can be accessed in two ways, either from the company's public website at https://www.nvenergy.com/, or directly via this link: https://drp.nvenergy.com/. NV Energy requires users of the DRP Web Portal to register and proceed through a multifactor authentication process using the free Microsoft Authenticator app prior to gaining access and each time a user logs into the DRP Web Portal. From the main page on NV Energy's website:

1. *On the upper right, click on* ***Clean Energy****.*

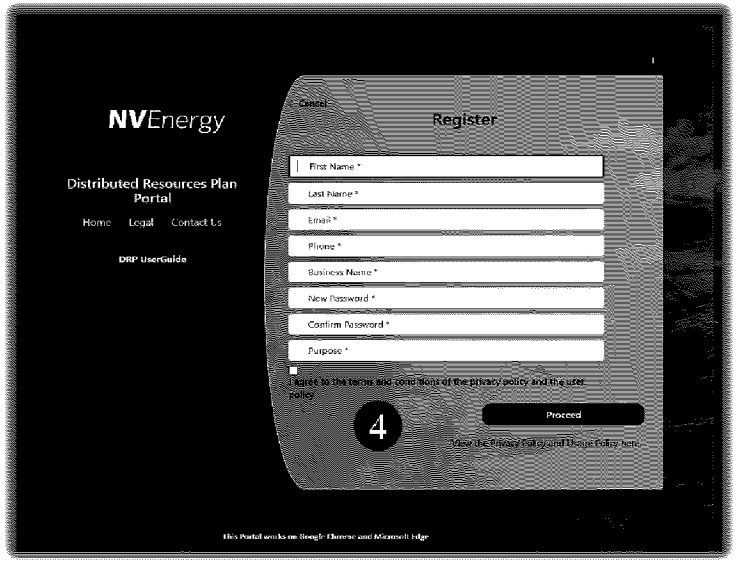
2. *Scroll all the way down to the bottom of the screen and click on* ***Distributed Resource Plan-Developer Portal****.*





3 *[Using the https://drp.nvenergy.com/ link will bring you directly to the DRP Web Portal login page.] Click on* ***Register*** *if you are a new user. If you have already registered, just enter your e-mail and password, click* ***Sign in****, and you will be brought to the Microsoft Authenticator screen shown in 5. below. If you forgot your password, or your password has expired, click* ***Forgot Password?*** *to reset it.*

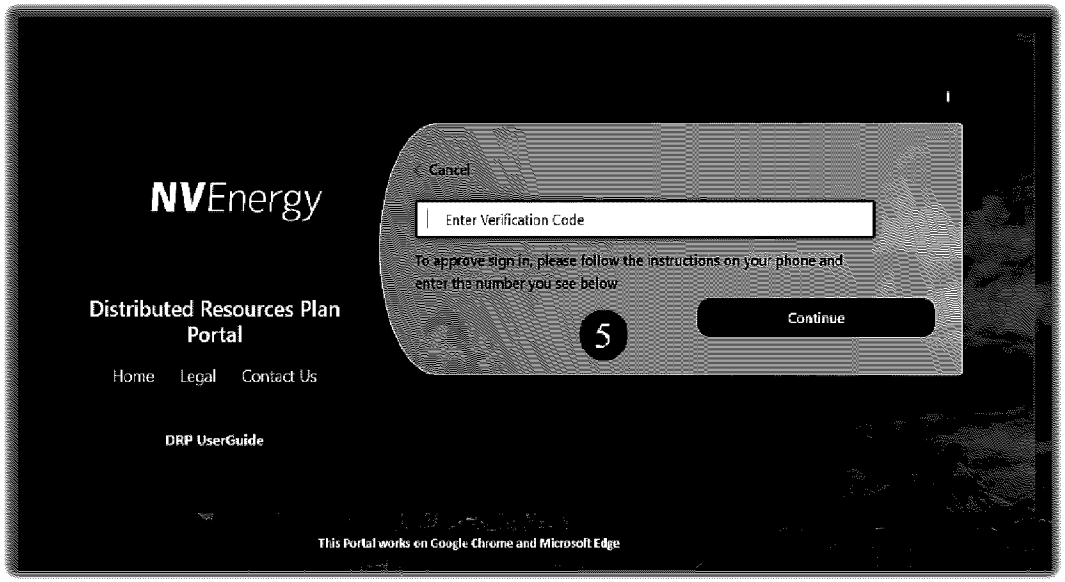




4 *If registering, enter the requested information and click the box agreeing to the terms and conditions of NV Energy's Privacy and Usage policies. These policies may be viewed by clicking on the red text. When finished, click* ***Proceed*** *and you will be brought to the Register screen shown in 6. below.*

NOTE: Users must download the free Microsoft Authenticator app onto a compatible mobile device such as a smart phone or tablet prior to the next step in the login process and follow the instructions in the app to create an account. Once a user has registered and attempts to log in, the Microsoft Authenticator app produces a rotating six-digit verification code that the user will be required to enter as the second step in the multifactor authentication process of the identity of the user. Do not delete the Microsoft Authenticator app as it will need to be used in each login process. Android OS users must use Version 6.0 or higher and iPhone users must use iOS Version 11.0 or higher to ensure compatibility with the Microsoft Authenticator app.

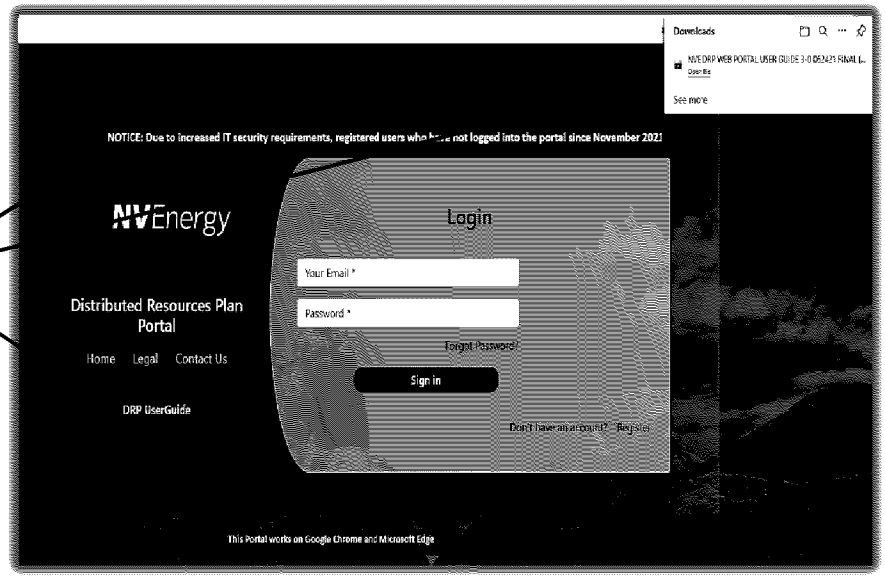
5 *Access the Microsoft Authenticator app on your mobile device, note the six digit code that the app provides, then enter that code into the* ***Enter Verification Code*** *space provided. When finished, click* ***Continue*** *and the next screen will be the DRP Web Portal landing page. (Users may click* ***Cancel*** *to return to the login screen.)*



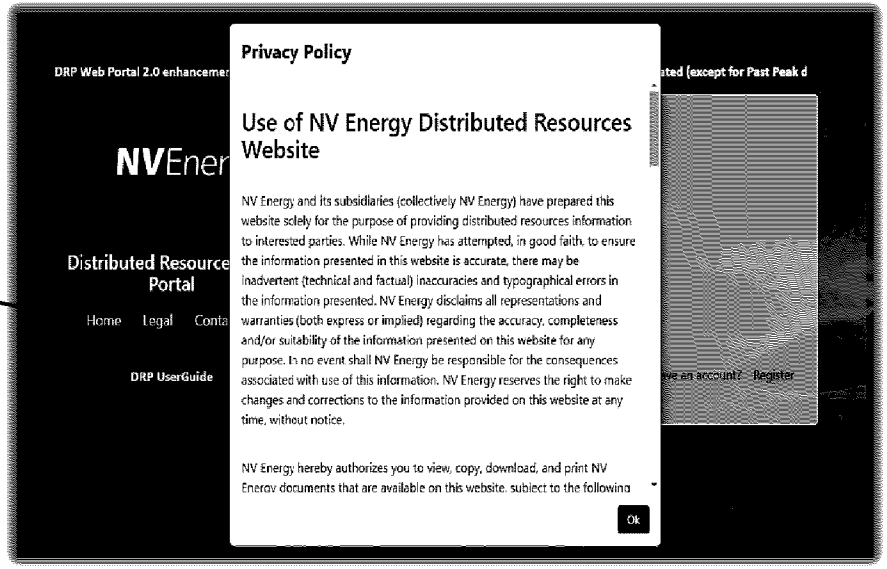


6 *If registering, the user will be brought to this screen from the screen shown in 4. above. Users may download the Microsoft Authenticator app from this screen if they do not already have it. Access the Microsoft Authenticator app on your mobile device, tap the + sign on the upper right, select the type of account, choose* ***Scan QR code*** *and scan the QR code on the DRP Web Portal registration screen. This will generate a six-digit code on the Microsoft Authenticator app. Enter that six-digit code into the* ***Enter Verification Code*** *space provided on the DRP Web Portal registration screen. When finished, click* ***Continue****. Users will then be redirected to the login screen in 3. above to login.*

*A scrolling newsletter across the top of the page contains announcements or status of activities. Click **DRP User Guide** to download the latest version of the User Guide. The downloaded file will appear in a popup box on the upper right of the screen. Click **Open File** to access the file.*



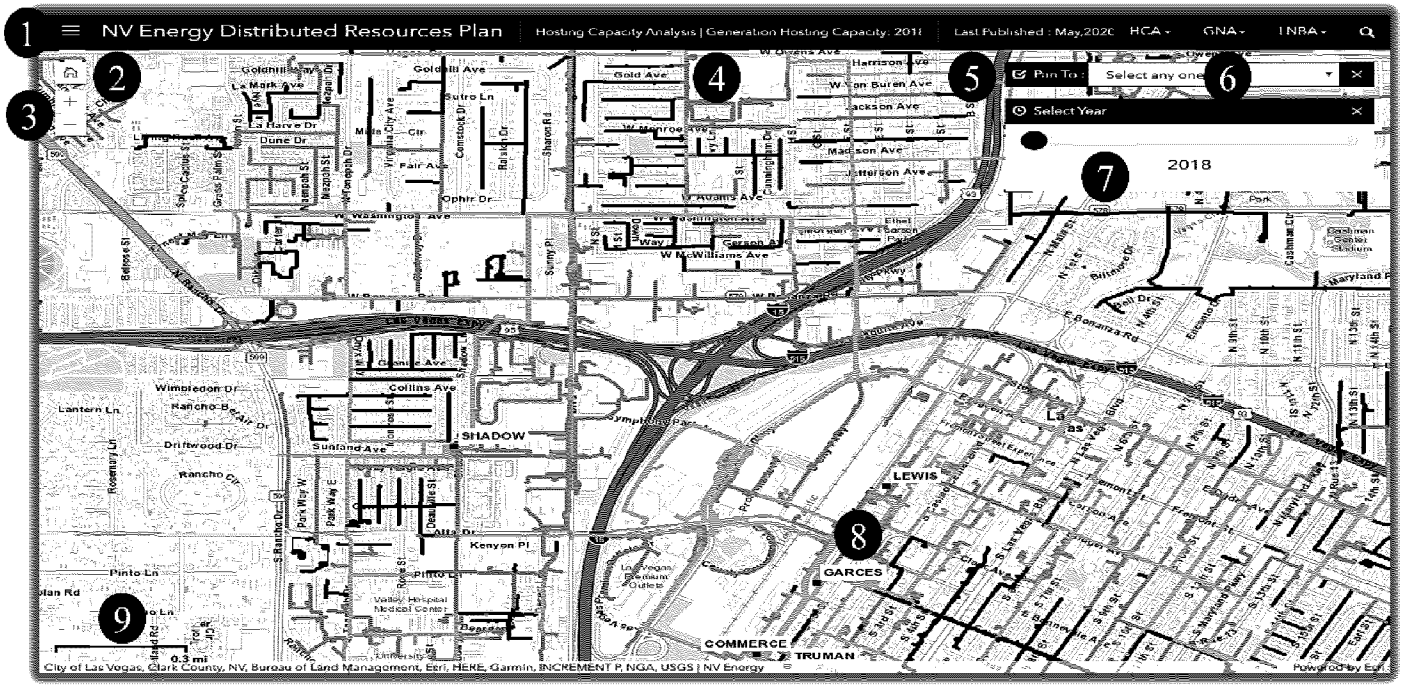
*Click **Home** to be brought back to the login page. Click **Legal** to access NV Energy's Privacy and Usage Policy. Click **Contact Us** to access a webpage containing contact phone numbers.*



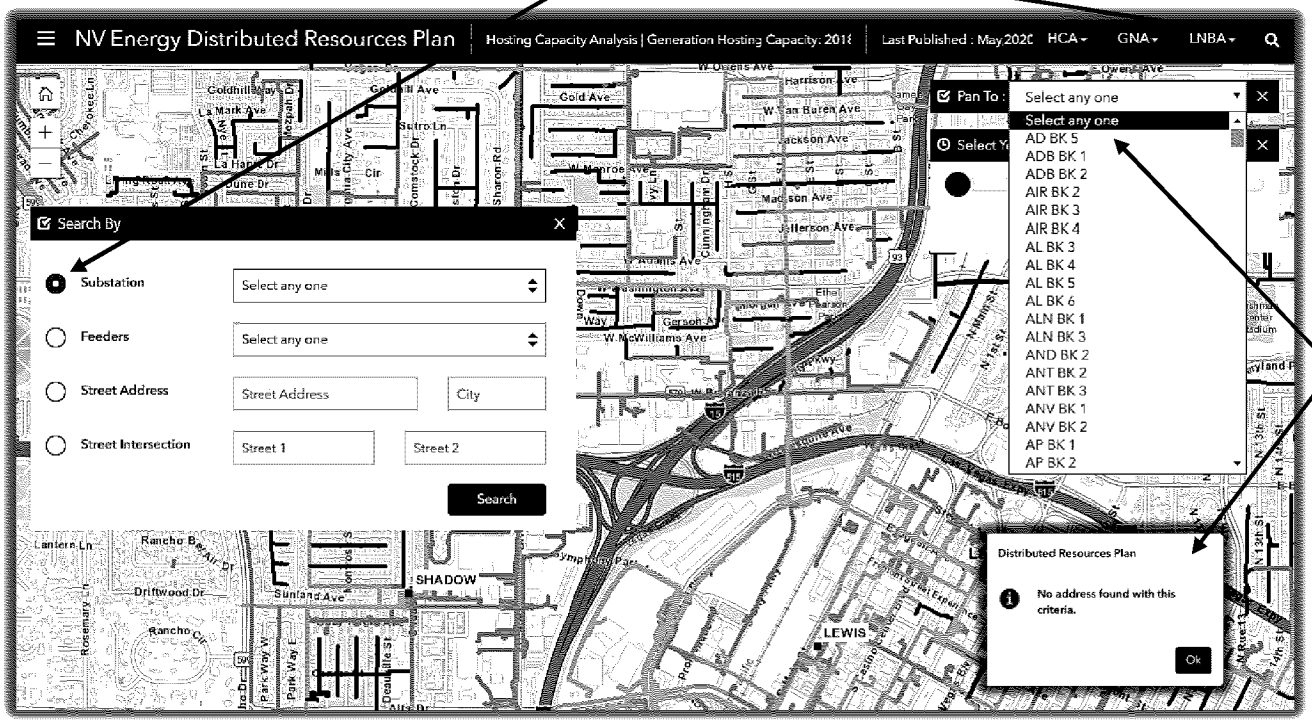
Navigation, Zoom & Levels

After successful login, the landing page is centered on the Las Vegas area at the 0.3 mile zoom level. The base year will progress annually (presently, it is 2022). Click and hold the left mouse button to drag the map and move in any direction.

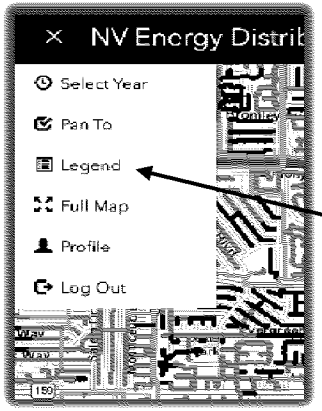
1. *Click the three-line "hamburger" symbol to access additional menu options.*
2. *Click the **Home** icon to return to the default location and zoom level.*
3. *Click + or - to zoom in or out, or use the click-wheel on the mouse.*
4. *The data and year being displayed is indicated here.*
5. *The month and year that data was last updated is shown here.*
6. *Click on **HCA**, **GNA**, or **LNBA** to display that data.*
7. *Move the slider to display data for different years.*
8. *Substations show as blue squares with blue name labels.*
9. *The scale indicator is on the bottom left of the map.*



*Click the **Magnifying Glass** icon to open a Search By box. Click the radio buttons on the left to select the desired search parameter, then either click on a 'Select any one' box to select the desired substation or feeder, or enter text into the boxes to find a street address or intersection. Click **Search** to begin the search. The map will move and be centered on the selected parameter(s). Substations and feeders will be highlighted in blue. Click anywhere on the map to remove the highlighting. Street addresses or intersections will be indicated with a red and yellow drop pin.*

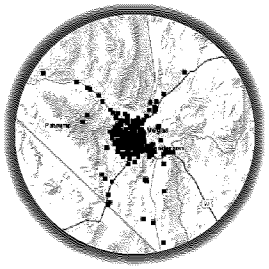


*Click 'Select any one' in the **Pan To** box to open a list of substation transformers. Select the desired transformer and the map will move and be centered on the feeders served from that transformer. The feeders will be highlighted blue. Click anywhere on the map to remove the highlighting. If all the feeders served from a transformer have been redacted, a popup will indicate that the transformer cannot be found.*

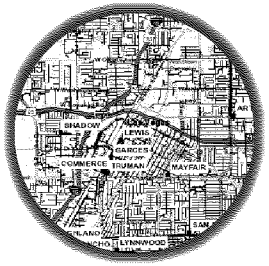


Clicking the three-line "hamburger" symbol provides access to the ***Select Year***, ***Pan To***, ***Legend***, ***Full Map***, ***Profile***, *and* ***Log Out*** *dropdown menu.*

Select Year *activates the popup slider box on the upper right side of the map.* ***Pan To*** *activates a search box on the upper right side of the map. Details of the* ***Legend*** *are explained below.* ***Full Map*** *removes the information bar across the top of the map.* ***Profile*** *activates a popup box wherein a user can edit their profile information.* ***Log Out*** *brings the user back to the login page.*



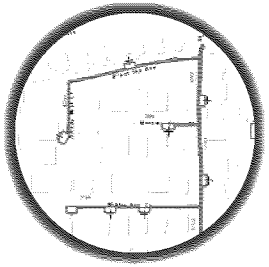
Starting at 100 miles zoom, substation locations appear as blue squares. At 6 miles zoom, they appear as green squares on the GNA screen, and as red squares on the LNBA screen.



At 4 miles zoom, substation name labels appear. At 1 mile zoom, feeders appear as black lines on the HCA screen, and colorization of feeders appears on the GNA and LNBA screens.



At 0.4 mile zoom, colorization of the feeders appears on the HCA screen and feeder sections can be clicked on to display data.



At 300 feet zoom, black crosses representing service transformers begin to appear on the HCA screen. The crosses are green on the GNA screen and are red on the LNBA screen.

Hosting Capacity Analysis

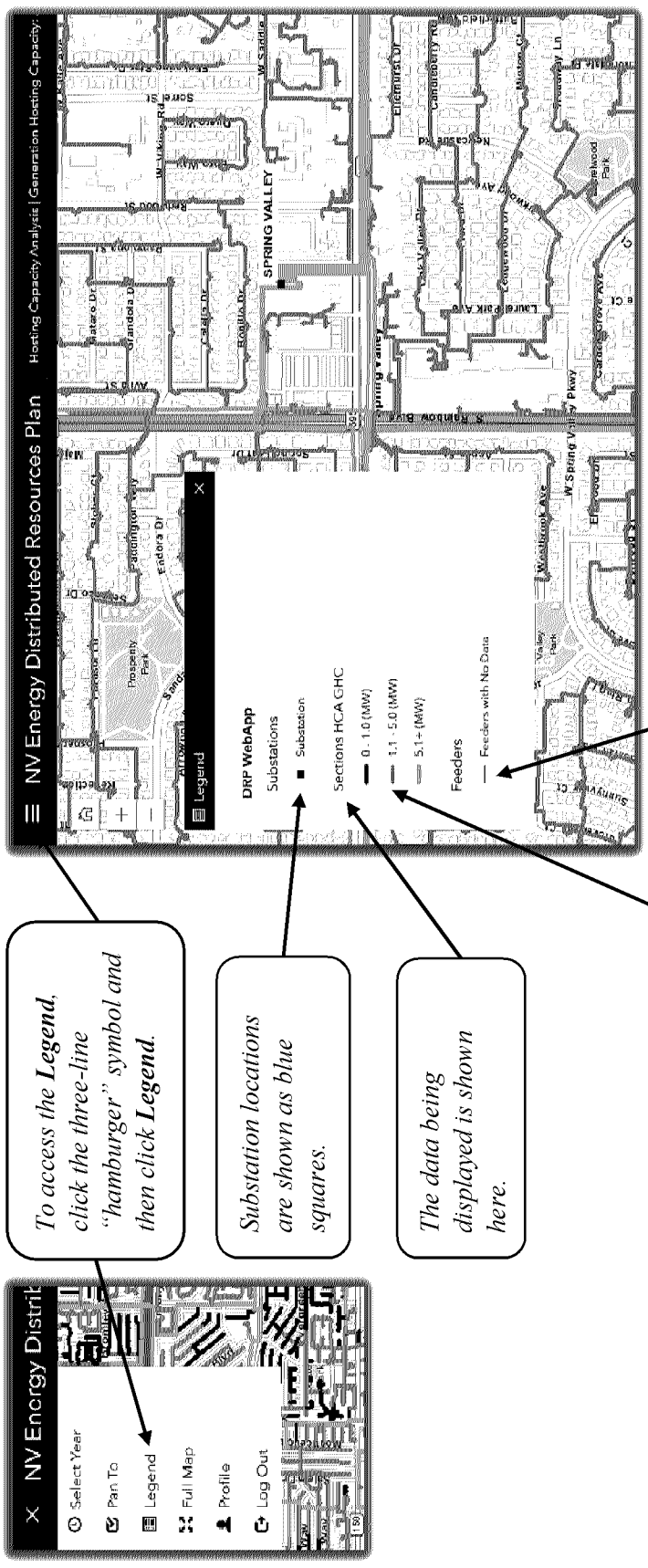
NV Energy performs its HCA studies using the Synergi Electric power flow software ("Synergi"). As available, 15-minute metered data is used to create an annual hourly loading profile for each electric distribution feeder. The highest and lowest loading days in each month for each feeder are determined from the loading profile data, and the resulting 576 loading data points are extracted for both kW and kVAR. The resulting *576 x 2* loading data points (24 hours times 12 data points for the highest loading day each month, plus 24 hours times 12 data point for the lowest loading day each month, times two for both kW and kVAR values) are provided to Synergi for the time-series HCA studies.

The approach to determine the hosting capacity on each section of NV Energy's feeders includes three scenarios: Uniform Generation, Uniform Load, and Solar PV. The Uniform Generation analysis case simulates the effects of distributed generation systems (*e.g.,* solar PV, wind, traditional generators, or the discharging of battery energy storage systems). Simulating this case as uniform generation across the analysis timeframe accounts for the myriad of actual future scenarios where DERs could be generating at a variety of levels and times throughout the day and year. The Uniform Load analysis case simulates the effects of additional load being imposed on the feeder sections (*e.g.,* load growth, charging of battery energy storage systems or electric vehicles, or demand response). Simulating this case as uniform load across the analysis timeframe accounts for the myriad of actual future scenarios where new load or load modifying programs could be interacting with each other at a variety of levels and times throughout the day and year. The Solar PV analysis case is the same as the Uniform Generation case but presents results focusing only on the hours of 10:00 a.m. through 4:00 p.m. when solar output is expected to be at its highest and ensures that no practical limits need to be placed on solar PV operation.

The HCA studies utilize several criteria to determine technical limitations: steady-state voltage (maximum 126 volts and minimum 114 volts), voltage variation (three-volt maximum variation for steady-state voltage, not reflective of transient voltage fluctuations or harmonics), and thermal loading (normal continuous thermal ratings of equipment). Regarding reverse power flow, a limit based upon reverse power flow at the headend of the feeder and/or thermal loading are both calculated in the studies (and the lower value is selected as the reverse power flow limit value) but are not presently used as a criterion that would limit the hosting capacity of a feeder section. NV Energy may introduce system protection and operational/reliability related criteria into the HCA studies in the near future.

The HCA studies are run on each section of NV Energy's feeders, providing the most granular results possible. The HCA data provided on the DRP Web Portal represents the results of these analyses that determine the available *incremental* hosting capacity (*i.e.*, the available incremental amount of DER capacity above whatever amount of DER capacity currently exists) on each section of NV Energy's feeders for the three scenarios referenced above.

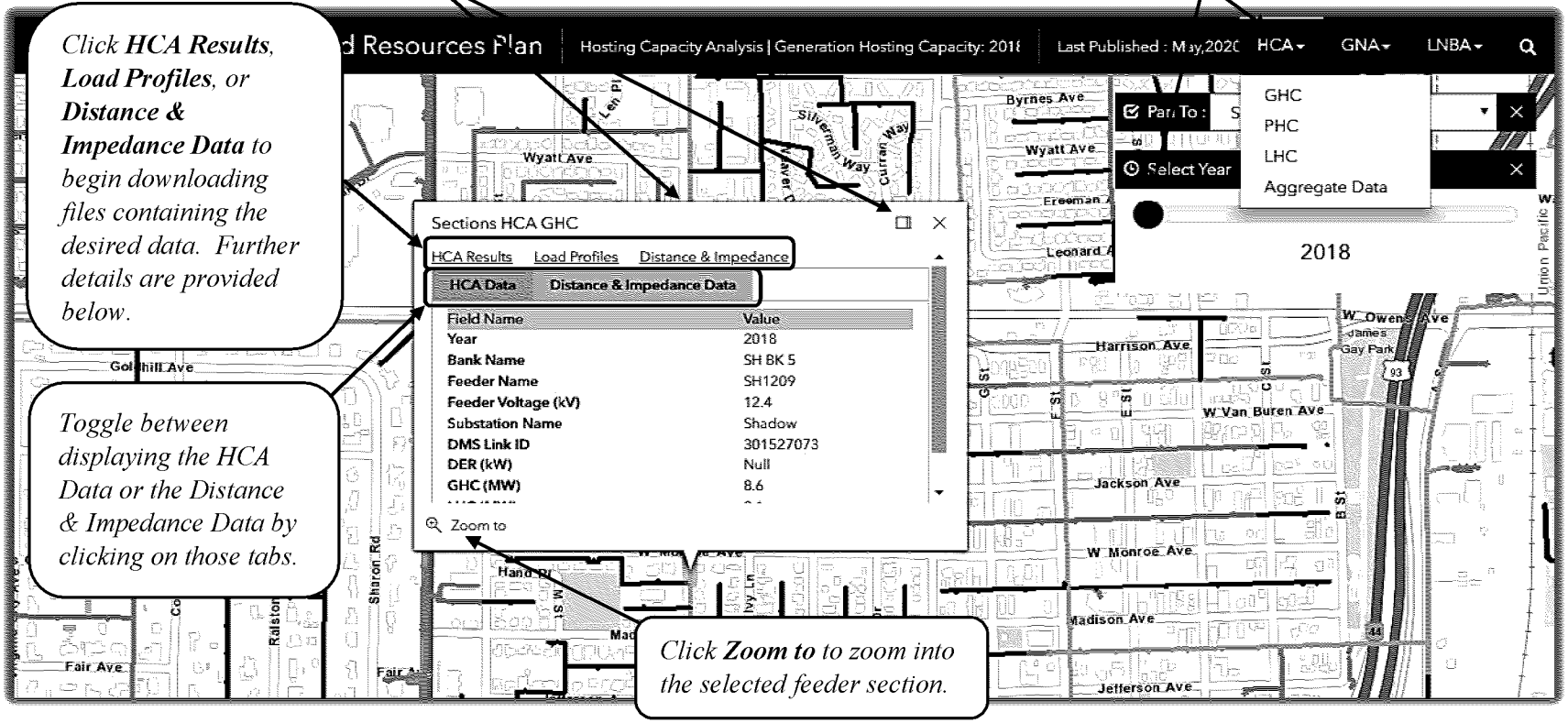
Legend Information



Popup Box Information

*Click on any colorized feeder section to reveal a popup box that provides detailed HCA information about the feeder section. The selected feeder section(s) is highlighted in blue. All the Field Names are defined below. Click on the **Dock** icon to dock the popup box on the top right corner of the screen as you pan to different locations or zoom.*

*Click on **HCA** to choose the GHC, PHC, or LHC views from the pulldown menu. The colorization of the feeders will change in accordance with these views, but the information provided in the popup box remains the same. Move the slider to display data for different years. The popup box will remain in place.*



*Click **HCA Results**, **Load Profiles**, or **Distance & Impedance Data** to begin downloading files containing the desired data. Further details are provided below.*

Toggle between displaying the HCA Data or the Distance & Impedance Data by clicking on those tabs.

*Click **Zoom to** to zoom into the selected feeder section.*

HCA Popup Box - HCA Data Field Name Definitions:

Year *– The year of the feeder loading data and feeder configuration used in the HCA.*

Bank Name *– The abbreviated name of the distribution substation transformer that the feeder section is connected to.*

Feeder Name *– The abbreviated name of the feeder that the feeder section is part of.*

Feeder Voltage (kV) *– The nominal voltage level of the feeder in kilovolts that the feeder section is part of.*

Substation Name *– The full name of the substation that the feeder section is connected to.*

DMS Link ID *– The unique identifying number for the feeder section in NV Energy's electronic mapping system.*

DER (kW) *– The installed total rated capacity of installed DER on the feeder section in kilowatts. "Null" means that there is no existing DER installed.*

GHC (MW) *– The Generation Hosting Capacity of the feeder section in megawatts.*

LHC (MW) *– The Load Hosting Capacity of the feeder section in megawatts.*

PHC (MW) *– The Photovoltaic Hosting Capacity of the feeder section in megawatts.*

HCA Popup Box - Distance & Impedance Data Field Name Definitions:

DMS Link ID *– The unique identifying number for the feeder section in NV Energy's electronic mapping system.*

Substation ID *– The abbreviated name of the distribution substation transformer that the feeder section is connected to.*

Feeder ID *– The abbreviated name of the feeder that the feeder section is part of.*

Analysis Year *– The year of the feeder loading data and feeder configuration used in the HCA.*

Miles Away *– The number of circuit miles from the substation to the selected feeder section.*

R1 Cumulative *– The cumulative positive sequence resistance from the substation to the selected feeder section.*

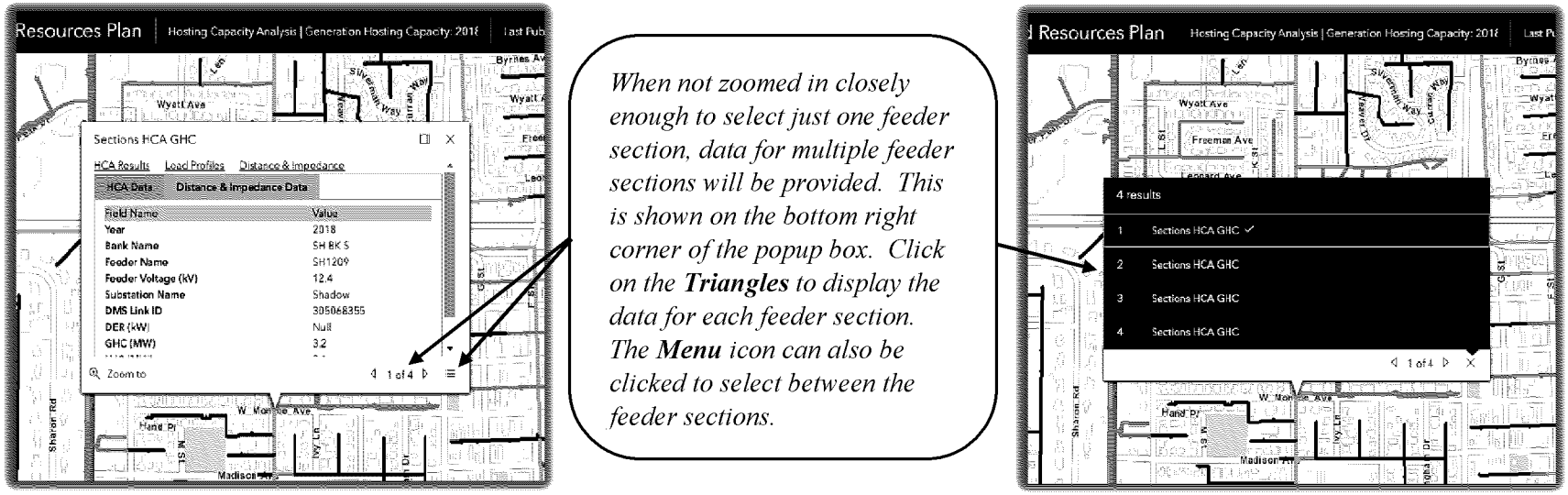
X1 Cumulative *– The cumulative positive sequence reactance from the substation to the selected feeder section.*

Z1 Cumulative *– The cumulative positive sequence impedance from the substation to the selected feeder section.*

R0 Cumulative *– The cumulative zero sequence resistance from the substation to the selected feeder section.*

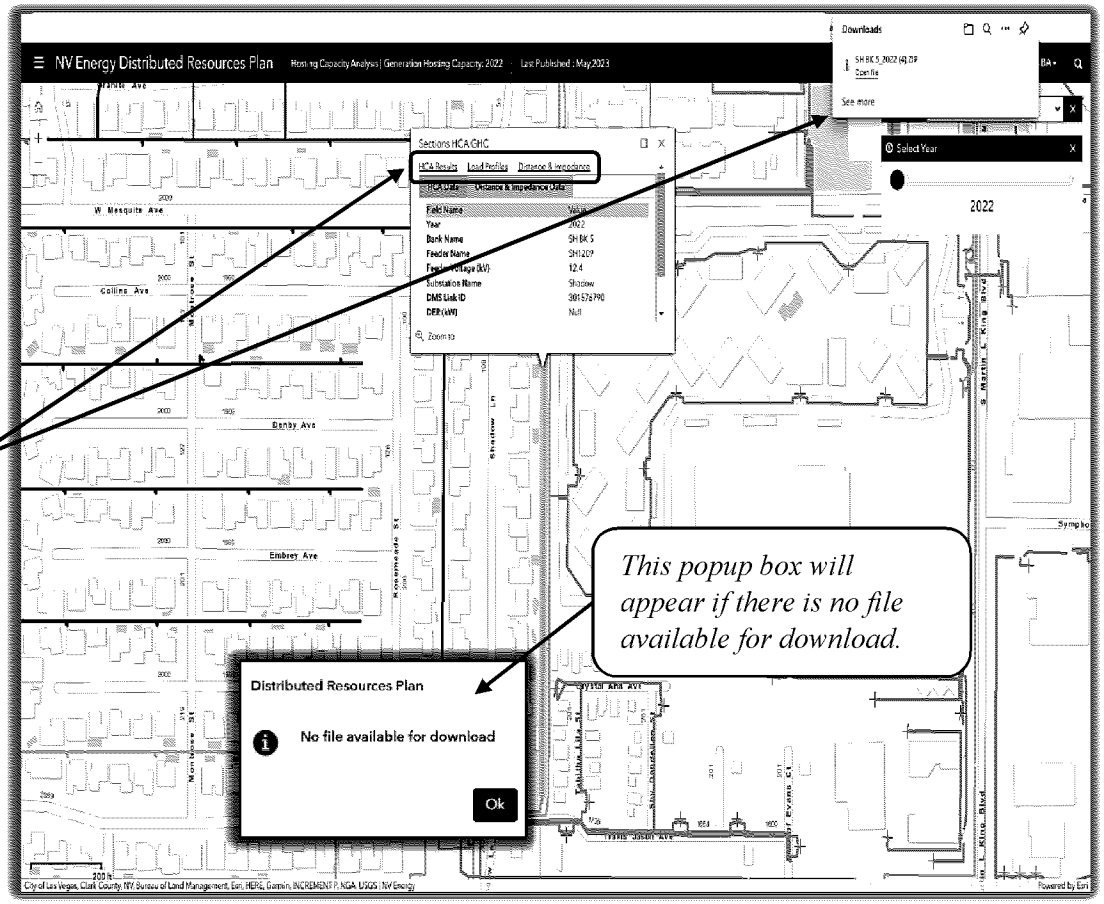
X0 Cumulative *– The cumulative zero sequence reactance from the substation to the selected feeder section.*

Z0 Cumulative *– The cumulative zero sequence impedance from the substation to the selected feeder section.*



File Download Information

*Click **HCA Results**, **Load Profiles**, or **Distance & Impedance Data** to begin downloading files containing the desired data. In this example, **HCA Results** was clicked, initiating the downloading of the Hosting Capacity Results file for the SH BK 5 substation transformer. Once successfully downloaded, a Zip file will appear on the upper right of the screen, where it can either be opened by clicking **Open File**, or the user's "Downloads" folder can be accessed. The data file will reside within the Zip file that has been placed in the user's "Downloads" folder. The Hosting Capacity Results files are in .csv format and the Load Profile data and Distance & Impedance data are in .xlsx format. Explanations for the columns in all three files are provided below.*



Hosting Capacity Results Data File Column Explanations:

RecId *– The unique ID of the analysis run, or the row in the file. It contains the date and time that the report resulting from the Hosting Capacity Analysis run in Synergi was created, along with a six-digit counter to uniquely identify each row in the file.*

Initiated *– This is the date and time that the recipe was initiated to run the Hosting Capacity Analysis in Synergi for the substation transformer.*

Region *– The region within NV Energy's territory. There are five regions designated in the Nevada Power Company territory: NVE-NE (Northeast), NVE-NW (Northwest), NVE-SE (Southeast), NVE-SW (Southwest), and NVE-Strip (Las Vegas Strip area). There are three regions designated in the Sierra Pacific Power Company territory: SPPC-TM (Truckee Meadows), SPPC-NE (Northeast), and SPPC-NW (Northwest).*

PlanArea *– The name of the substation.*

SubId *– The unique identifier for the substation transformer, which begins with either a two- or three-letter abbreviation for the substation, followed by the abbreviation "BK" which is short for "bank", and then the number identifying the substation transformer (or paralleled pair of substation transformers since Synergi gives only one number for a paralleled pair).*

SubTranId *– This column is not used.*

FeederId *– The unique identifier for the feeder, which begins with either a two- or three-letter abbreviation for the substation, followed by the number identifying the feeder.*

SectId *– The unique identifier for the feeder section.*

AnalysisYear *– The year for the analysis, which may contain forecasted amounts of DER, forecasted loading, and anticipated system configuration for that year.*

UserComment *– This column is not used.*

Settings *– This is "IHCA", which means "Incremental Hosting Capacity Analysis".*

Season *– The month of the analysis in that row; January through December.*

DayType *– The type of day for the analysis in that row; either "Peakday" (a high loading day) or "Minday" (a low loading day).*

HourOfDay *– The hour of the day for the analysis in that row: 1 through 24.*

LimitFound *– This is "1", which indicates that a limit was found.*

MaxGenMw *– The Generation Hosting Capacity for that analysis run (row) which is the lowest of the values in the GenMw_MaxVolts, GenMw_DeltaVolts, GenMw_LoadingLim, GenMw_RevFlow, and GenMw_MinVolts columns. [However, since the data in the GenMw_RevFlow column is for informational purposes only at this time and is not used as a limiting criteria to report Hosting Capacity, the lowest of the values in the GenMw_MaxVolts, GenMw_DeltaVolts, GenMw_LoadingLim, and GenMw_MinVolts columns for all of the analysis runs is what is reported as the GHC for the feeder section.]*

MaxLoadMw *– The Load Hosting Capacity for that analysis run (row) which is the lowest of the values in the LoadMw_MinVolts and LoadMw_LoadingLim columns. [The lowest of the values in this column for all of the analysis runs is the value that is reported as the LHC for the feeder section.]*

GenMw_MaxVolts *– The maximum Generation (or Photovoltaic) Hosting Capacity in MW based upon the high value of the steady-state voltage criterion in the analysis.*

GenMw_DeltaVolts *– The maximum Generation (or Photovoltaic) Hosting Capacity in MW based upon the voltage variation criterion in the analysis.*

GenMw_LoadingLim *– The maximum Generation (or Photovoltaic) Hosting Capacity in MW based upon the thermal loading criterion in the analysis.*

GenMw_RevFlow *– The maximum Generation (or Photovoltaic) Hosting Capacity in MW based upon the reverse power flow criteria in the analysis (limited either on the basis of reverse flow at the feeder section or reverse flow at the head-end of the feeder).*

GenMw_MinVolts *– The maximum Generation (or Photovoltaic) Hosting Capacity in MW based upon the low value of the steady-state voltage criterion in the analysis.*

LoadMw_MinVolts *– The maximum Load Hosting Capacity in MW based upon the low value of the steady-state voltage criterion in the analysis.*

LoadMw_LoadingLim *– The maximum Load Hosting Capacity in MW based upon the thermal loading criterion in the analysis.*

Load_DLC_Factor *– Unable to find explanation in the Synergi documentation. This column will be eliminated from the file in the future.*

PV_Factor *– Unable to find explanation in the Synergi documentation. This column will be eliminated from the file in the future.*

Load Profile Data File Column Explanations:

Feeder *– The unique identifier for the feeder, which begins with either a two- or three-letter abbreviation for the substation, followed by the number identifying the feeder.*

Date *– The date of the load data in that row.*

Month *– The month of the load data in that row.*

Day Type *– The type of day for the load data in that row; either "Peakday" (a high loading day) or "Minday" (a low loading day).*

MW Hour # *– The load in MW for the 24 hours of the day (one column for each hour).*

MVAR Hour # *– The load in MVAR for the 24 hours of the day (one column for each hour).*

Distance & Impedance Data File Column Explanations:

SubId *– The abbreviated name of the distribution substation transformer that the feeder section is connected to.*

FeederId *– The abbreviated name of the feeder that the feeder section is part of.*

SectId *– The unique identifying number for the feeder section in NV Energy's electronic mapping system.*

AnalysisYear *– The year of the feeder loading data and feeder configuration used in the HCA.*

MilesAway *– The number of circuit miles from the substation to the selected feeder section.*

R1_Cmltv *– The cumulative positive sequence resistance from the substation to the selected feeder section.*

X1_Cmltv – *The cumulative positive sequence reactance from the substation to the selected feeder section.*

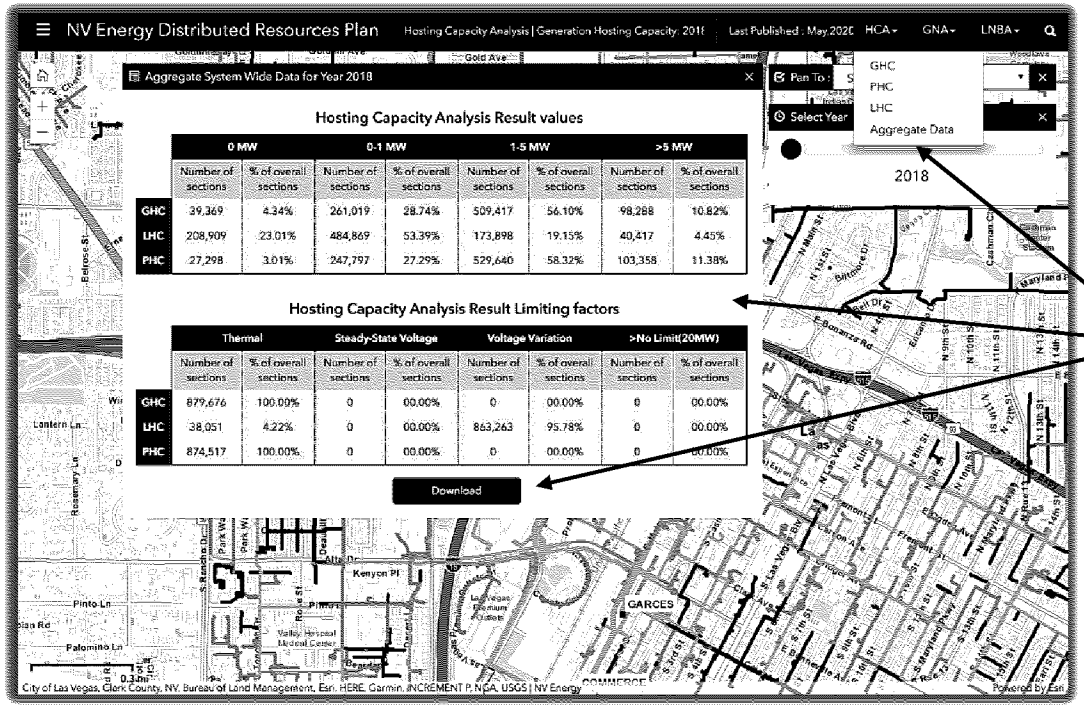
Z1_Cmltv – *The cumulative positive sequence impedance from the substation to the selected feeder section.*

R0_Cmltv – *The cumulative zero sequence resistance from the substation to the selected feeder section.*

X0_Cmltv – *The cumulative zero sequence reactance from the substation to the selected feeder section.*

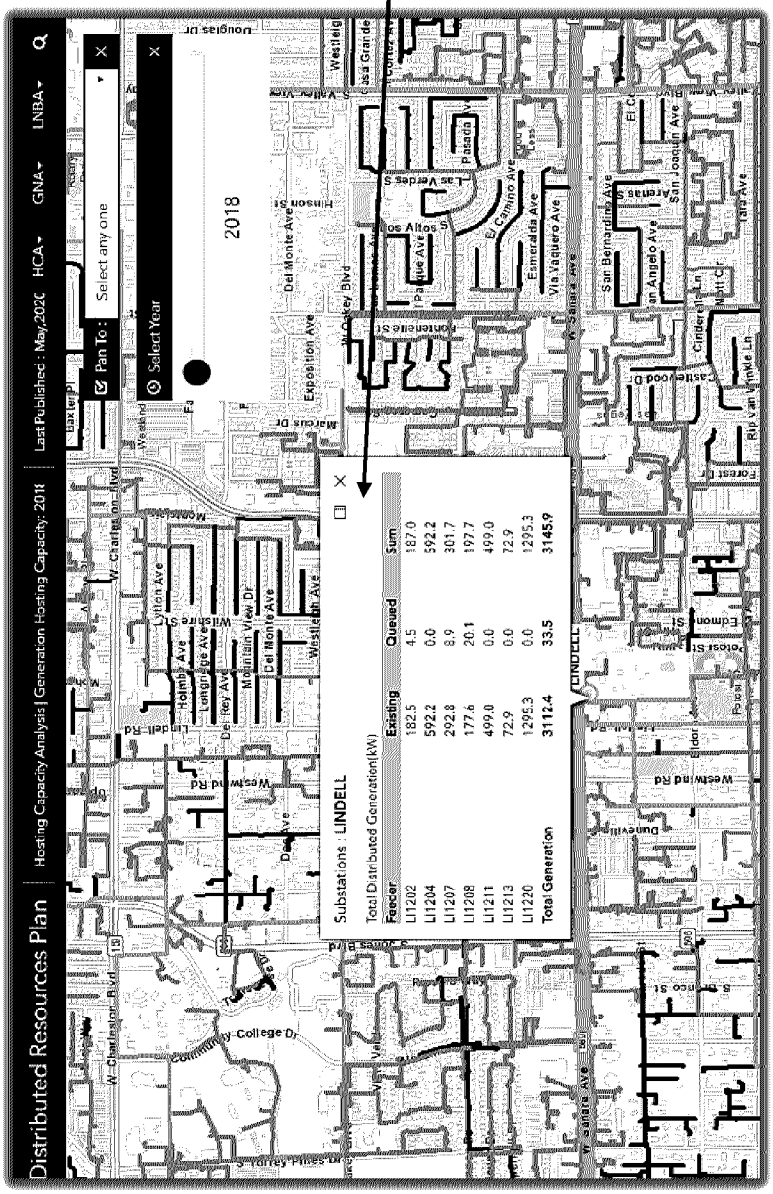
Z0_Cmltv – *The cumulative zero sequence impedance from the substation to the selected feeder section.*

Aggregate Data Information



*Click **Aggregate Data** on the **HCA** dropdown list to display a window containing aggregate data about the HCA results and limiting factors. The system will take some time to calculate the data before the window is displayed. This information is year-specific and will change as the **Select Year** slider is moved to different years. Click **Download** to initiate the downloading of a .csv format file containing this information. Once successfully downloaded, the file will appear on the upper right of the screen, where it can either be opened by clicking on **Open File**, or the user's "Downloads" folder can be accessed which will contain the file.*

Distributed Generation Information

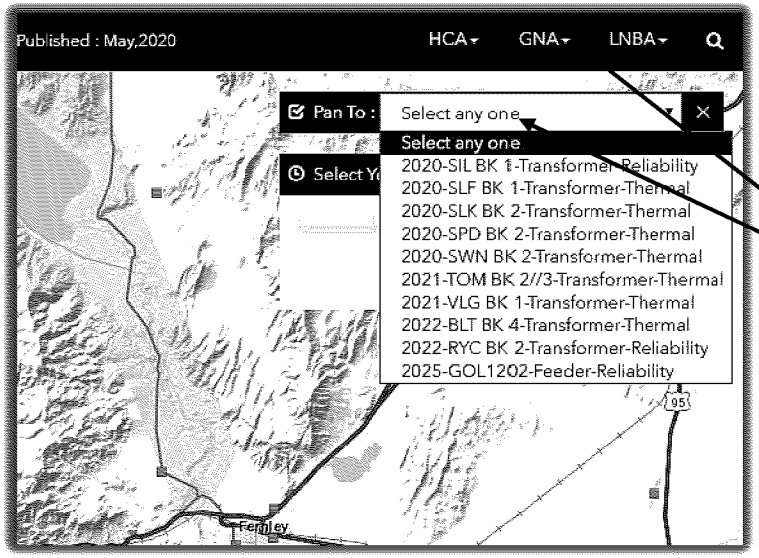


On the HCA screen, click on any blue substation square to reveal a popup box containing information about the distributed generation capacity currently connected to and in the queue for each feeder served from the substation and the total for the substation itself. This information is updated monthly after the 7th of each month.

Grid Needs Assessment

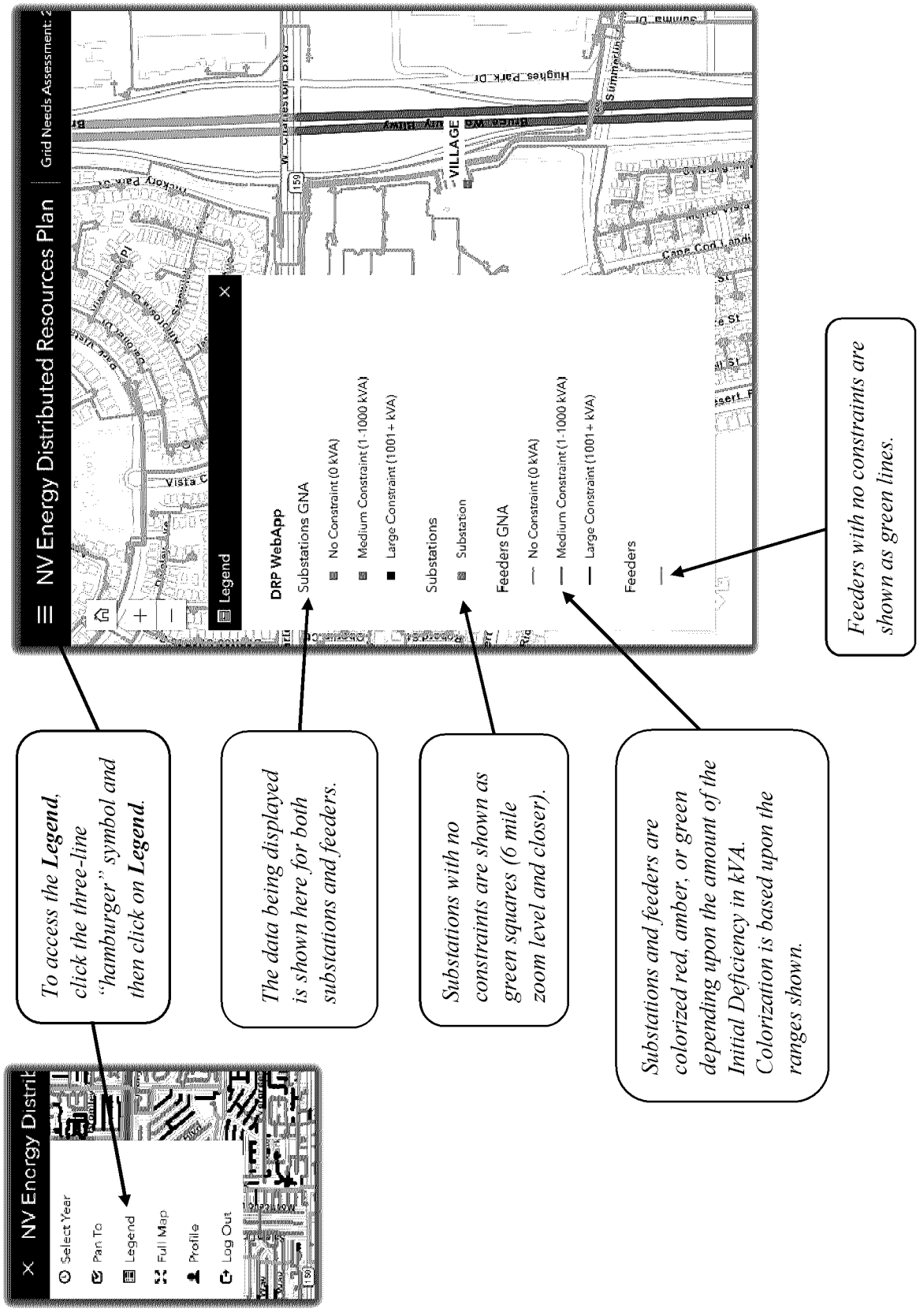
NV Energy's GNA encompasses the constraints on the electric grid, traditional wired solutions to those constraints, determination of NWA's suitability to mitigate identified constraints, and potential NWA solutions to those constraints. NV Energy's capital expenditure plan is used as the source to initially identify existing or forecasted constraints on the electric grid and the traditional wired solutions planned to address those constraints. These constraints are then filtered to extract only those requiring investment based upon upgrade/reliability and system reinforcement reasons (essentially, those constraints based upon thermal loading, voltage, or reliability reasons where a reduction in peak demand loading or energy consumption, or load shifting, would eliminate or defer the constraint). The remaining constraints and their associated traditional wired solutions are further filtered to focus only on those in the future six-year timeframe. As a result, the GNA covers six years beyond the current year and presents data associated with the identified constraints on NV Energy's distribution system that could be mitigated by an NWA (DER-type) solution on the Web Portal.

Through NV Energy's NWA analysis, data identifying the constraints (*e.g.,* the year, substation, facility identifier, facility type, constraint type, operational condition, and seasonal identification), the potential NWA solutions (*e.g.*, capacities of energy efficiency, demand response, solar PV, battery energy storage, Conservation Voltage Reduction, and an estimated cost), and the traditional wired solutions (*e.g.,* project name, estimated cost, and reserve margin) are determined.



*Click on **GNA** and then **Map** to access the GNA map. Click on 'Select any one' in the **Pan To** box to view a list of constraints. Select any constraint and the map will move and be centered on that constraint. The constraint will be highlighted blue. Click anywhere on the map to remove the highlighting.*

Legend Information

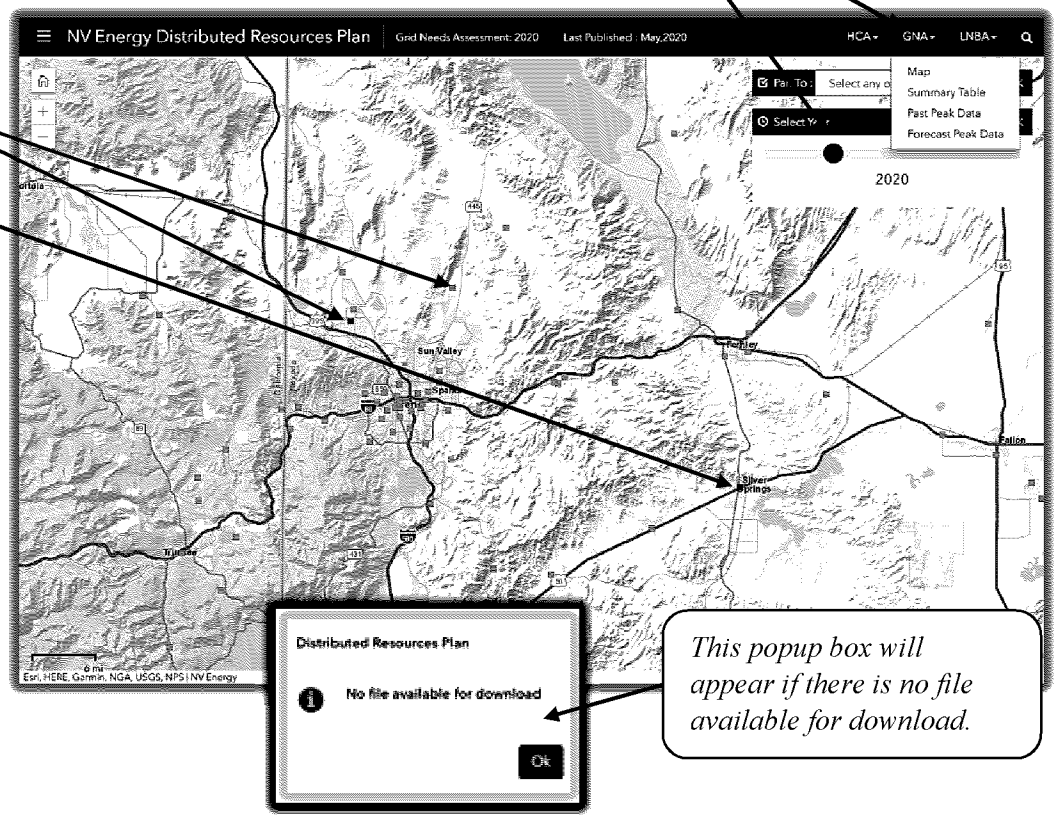


GNA Screen Information

*Click on **GNA** to reveal a dropdown menu with several options. Click on **Map** to show the GNA map. The majority of the substations and feeders on the map will show as green indicating that there is no identified constraint in the selected year. Move the slider to display data for different years. Click on **Summary Table**, **Past Peak Data**, or **Forecast Peak Data** to initiate downloading of the data files for each of these items. Once downloaded, a Zip file containing the requested file will appear on the bottom left of the screen.*

Colorization of constraints at the substation level occurs at the 6 mile zoom level on the GNA screen. Substations colored red or amber can be clicked on to display data.

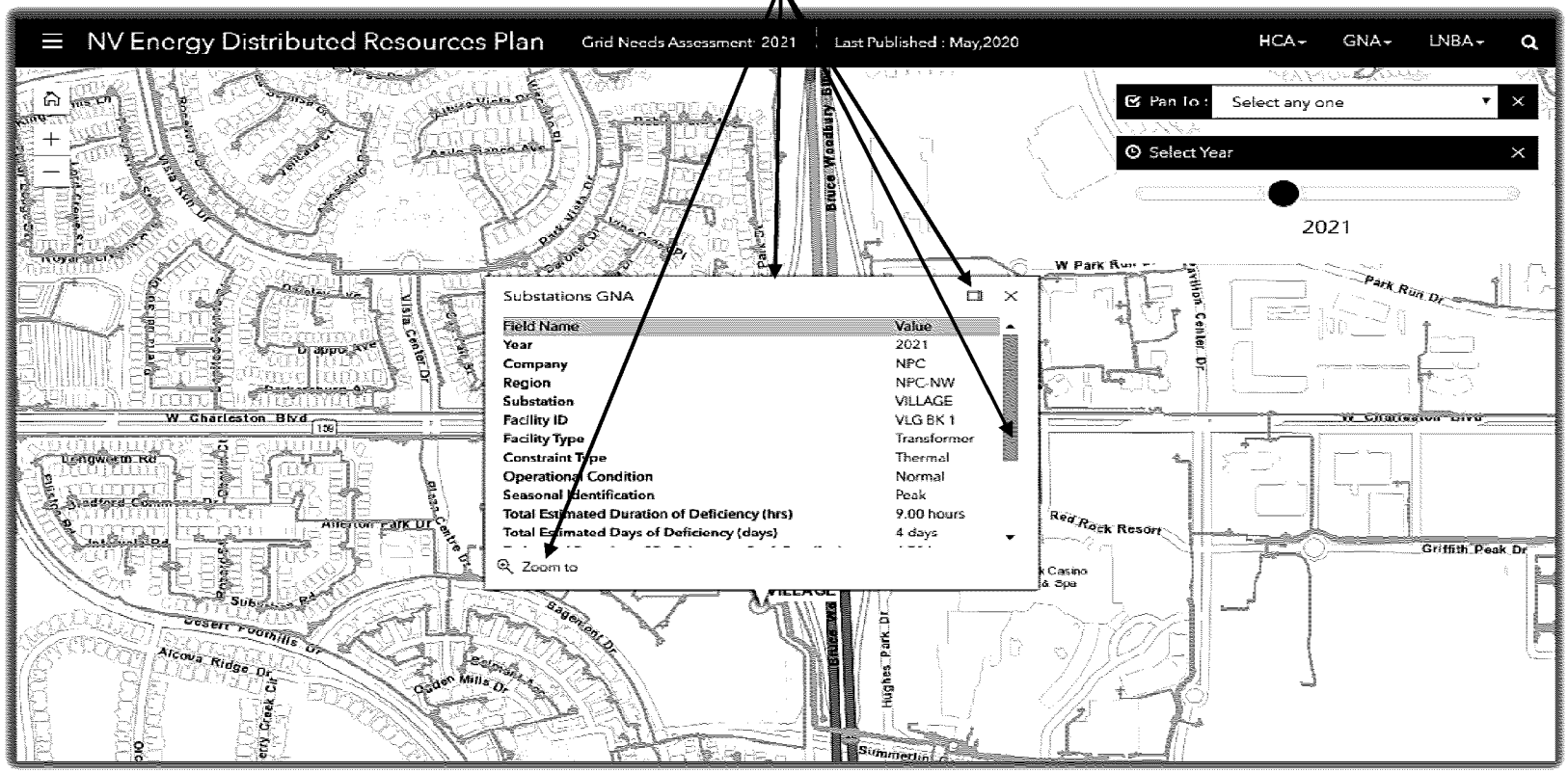
*When the user clicks on **Summary Table**, **Past Peak Data**, and **Forecast Peak Data**, Zip files containing the requested download files will appear in the upper right of the screen. The files can either be opened by clicking on **Open File**, or the user's "Downloads" folder can be accessed. The data file will reside within the Zip file that has been placed in the user's "Downloads" folder. The **Summary Table**, **Past Peak Data**, and **Forecast Peak Data** files are in .xlsx format.*



This popup box will appear if there is no file available for download.

Popup Box Information

Click on any amber- or red-colored substation or feeder section to reveal a popup box that provides detailed GNA information about the distribution facility. The substation or feeder section will be highlighted in blue. Scroll down in the popup box to reveal the remaining data. The Field Names are defined below. Click on ***Zoom to*** *to zoom into the selected item. Click on the* ***Dock*** *icon to dock the popup box on the top right corner of the screen as you pan to different locations or zoom.*



GNA Popup Box Field Name and GNA Summary Table Column Definitions:

Year *– The year that the constraint on the distribution system first occurs, or the year in which NV Energy plans to mitigate the constraint.*

Company *– The territory in which the constraint is forecasted to occur; either NPC or SPPC.*

Region *– The region within NV Energy's territory in which the constraint is forecasted to occur. There are five regions designated in the Nevada Power Company territory: NVE-NE (Northeast), NVE-NW (Northwest), NVE-SE (Southeast), NVE-SW (Southwest), and NVE-Strip (Las Vegas Strip area). There are three regions designated in the Sierra Pacific Power Company territory: SPPC-TM (Truckee Meadows), SPPC-NE (Northeast), and SPPC-NW (Northwest).*

Substation *– The name of the substation in which the constrained distribution system facility is located or is served from.*

Facility ID *– The unique identifier for the constrained distribution system facility, which begins with either a two- or three-character abbreviation for the substation, the abbreviation "BK" if the facility is a substation transformer, and a number identifying either the position of the substation transformer in the substation or the feeder breaker number if the facility is a distribution feeder. The symbol "//" means that two substation transformers are normally operated in parallel with each other.*

Facility Type *– The type of constrained distribution facility (e.g., transformer or feeder).*

Constraint Type *– The type of constraint, including, reliability, thermal, or voltage.*

Operational Condition *– The operating condition in which the constraint occurs, including, normal, unplanned contingency, or planned abnormal conditions (e.g., during scheduled maintenance or construction).*

Seasonal Identification *– The season of the year in which the constraint mainly occurs, including, Summer Peak (generally, June through September), Winter Peak (generally, December through February), Off-Peak (generally, October, November, March, April and May), or All (occurs almost throughout the year). This is subjectively based on the Total Estimated Duration of Deficiency in 2029 and the Total Estimated Days of Deficiency in 2029.*

Total Estimated Duration of Deficiency (hrs) *– Based upon forecasted annual 15-minute load curve information, this is the estimated total number of hours in the year 2029 that the forecasted loading will be above the established limit (i.e., there will be a deficiency). The year 2029 was chosen for this and other parameters as it is the last year in the six-year timeframe from the year of NV Energy's current DRP filing, and the last year covered by the GNA.*

Total Estimated Days of Deficiency (days) *– Based upon forecasted annual 15-minute load curve information, this is the estimated total number of days in the year 2029 that the forecasted loading will be above the established limit at any time during that day.*

Estimated Duration of Deficiency on Peak Day (hrs) *– Based upon forecasted annual 15-minute load curve information, this is the estimated total number of hours on the forecasted peak load day in the year 2029 that the forecasted loading will be above the established limit.*

Criteria (kVA) *– This is the criteria used to establish the constraint (i.e., the established limit). Most often, this is the normal continuous rating of the distribution facility in kVA on which the constraint occurs.*

Initial Deficiency (kVA) *– This is the amount of the constraint in kVA, as compared to the Criteria, that either exists today, or is forecasted to exist in the first year the constraint occurs.*

Estimated Maximum Deficiency (kVA) *– This is the amount of the constraint in kVA, as compared to the Criteria, which is forecasted to exist in 2029. In comparison to the Initial Deficiency, this figure can help to gauge how the constraint may be increasing or decreasing over time.*

T and D Infrastructure Upgrade Project Name *– The name of the approved traditional T&D capital upgrade project planned to address the constraint.*

Estimated Cost ($) *– The estimated cost in today's dollars for the approved traditional T&D capital upgrade project planned to address the constraint.*

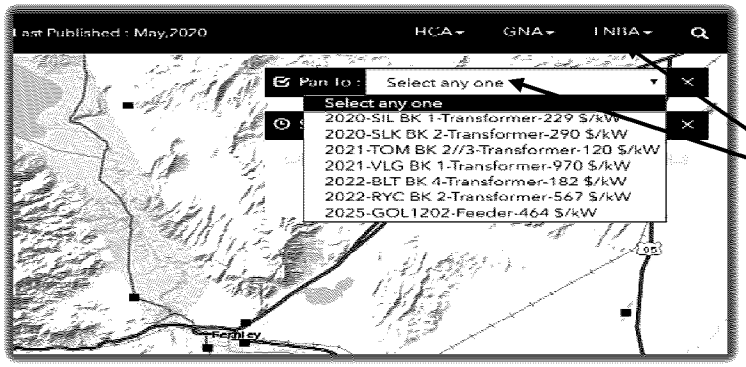
T and D Infrastructure Upgrade Reserve Margin (kVA) *– The estimated amount of incremental capacity in kVA that the traditional T&D capital upgrade project will install in 2029, above what is necessary to accommodate the Estimated Maximum Deficiency.*

Locational Net Benefits Analysis

NV Energy attempts to determine both the quantitative and qualitative costs and benefits of deploying DERs at different locations on the electric grid to identify the net value of such deployment. The system-level benefit areas presently included in the LNBA are: avoided energy, generation capacity, energy arbitrage, and ancillary services. Future system-level benefit areas that NV Energy plans to include are renewable portfolio standard integration and greenhouse gas emissions. The location-specific cost and benefit areas presently included in the LNBA are: transmission upgrade estimated cost, transmission upgrade OMAG, distribution upgrade estimated cost, distribution upgrade OMAG, and transmission and distribution losses. A "deferral value" is calculated based upon the distribution upgrade estimated cost and the total capacity of the determined potential NWA solution. For example, if the distribution upgrade estimated cost is $2,000,000 and the total capacity of the NWA solution for the same identified constraint is 5,000 kW, then a distribution upgrade deferral value of $400/kW is calculated ($2,000,000 / 5,000 kW). The deferral value is meant only as a comparative gauge between constraints indicating where a better opportunity may exist to defer a comparatively higher cost distribution upgrade by deploying a comparatively smaller capacity (and theoretically, lower-cost) NWA solution. It is not meant to indicate that deploying an NWA solution of a certain kW capacity will achieve a benefit or value in a dollar amount equivalent to the NWA solution's capacity in kW times the $/kW. As noted below, it is this deferral value that determines the colorization of the substations and feeders on the LNBA screen. A future location-specific benefit area that NV Energy plans to include is reliability/power quality.

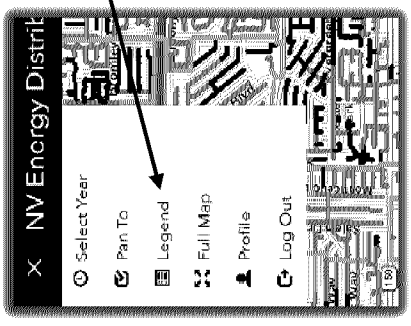
NV Energy uses a present worth of revenue requirement ("PWRR") financial analysis to compare a traditional wired solution option against an NWA and deferred traditional wired solution option. The quantitative values for the system-level benefits and location-specific costs and benefits are used in and generated from the PWRR analysis.

Similar to its GNA, NV Energy performs its LNBA covering six years beyond the current year and presents data associated with the identified constraints on its distribution and transmission systems that could be mitigated by an NWA (DER-type) solution on the Web Portal.

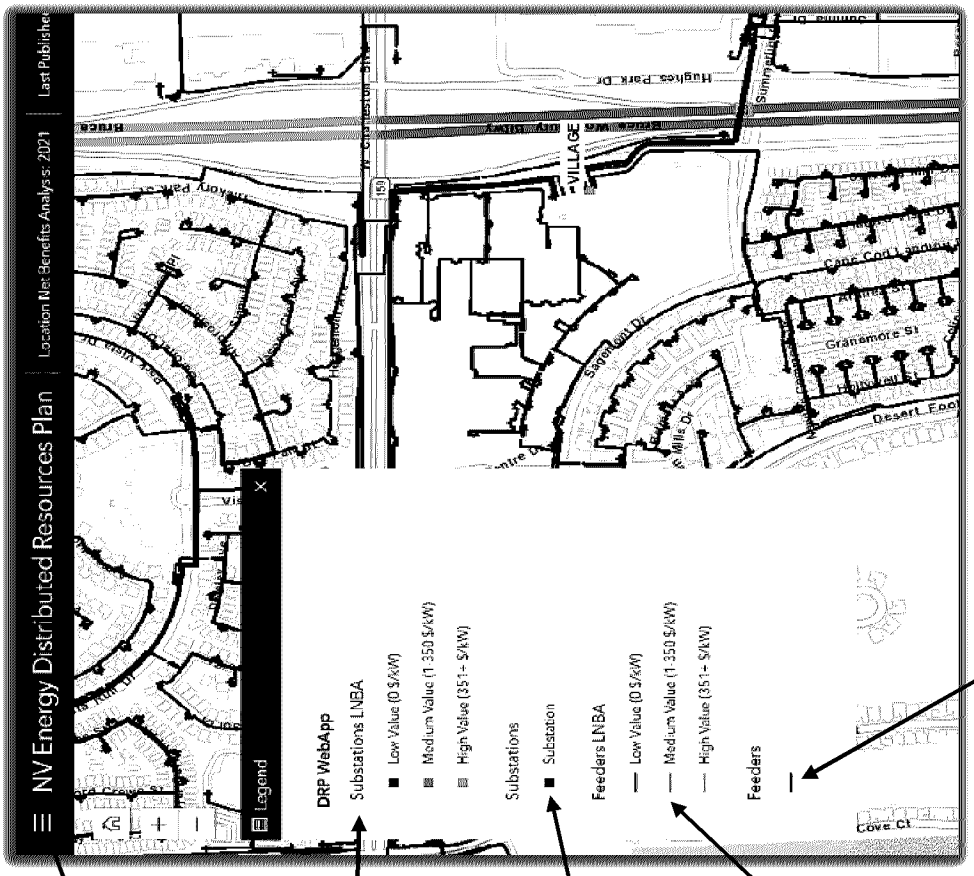


*Click on **LNBA** and then **Map** to access the LNBA map. Click on 'Select any one' in the **Pan To** box to view a list of constraints. Select any constraint and the map will move and be centered on that constraint. The constraint will be highlighted blue. Click anywhere on the map to remove the highlighting.*

Legend Information



*To access the **Legend**, click the three-line "hamburger" symbol and then click on **Legend**.*



The data being displayed is shown here for both substations and feeders

Substations with low value are shown as red squares (6 mile zoom level and closer).

Substations and feeders are colorized red, amber, or green depending upon the amount of the Distribution Upgrade Deferral Value in $/kW. Colorization is based upon the ranges shown.

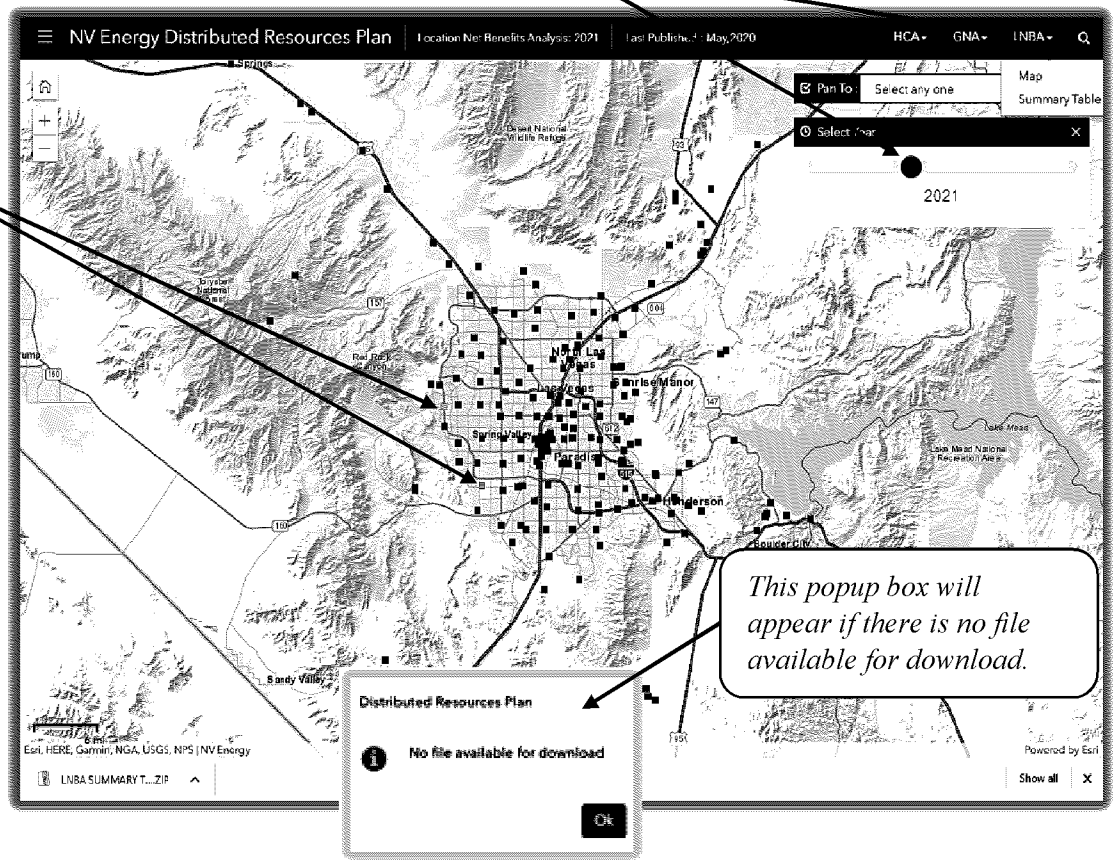
Feeders with low value are shown as red lines.

LNBA Screen Information

*Click on **LNBA** to reveal a dropdown menu with several options. Click on **Map** to show the map. The majority of the substations and feeders on the map will show as red indicating that there is low LNBA value in the selected year. Move the slider to display data for different years. Click on **Summary Table** to initiate downloading of the data file containing this information. Once downloaded, a Zip file containing the requested file will appear on the bottom left of the screen.*

Colorization of locational net benefits at the substation level occurs at the 6 mile zoom level on the LNBA screen. Substations colored green or amber can be clicked on to display data.

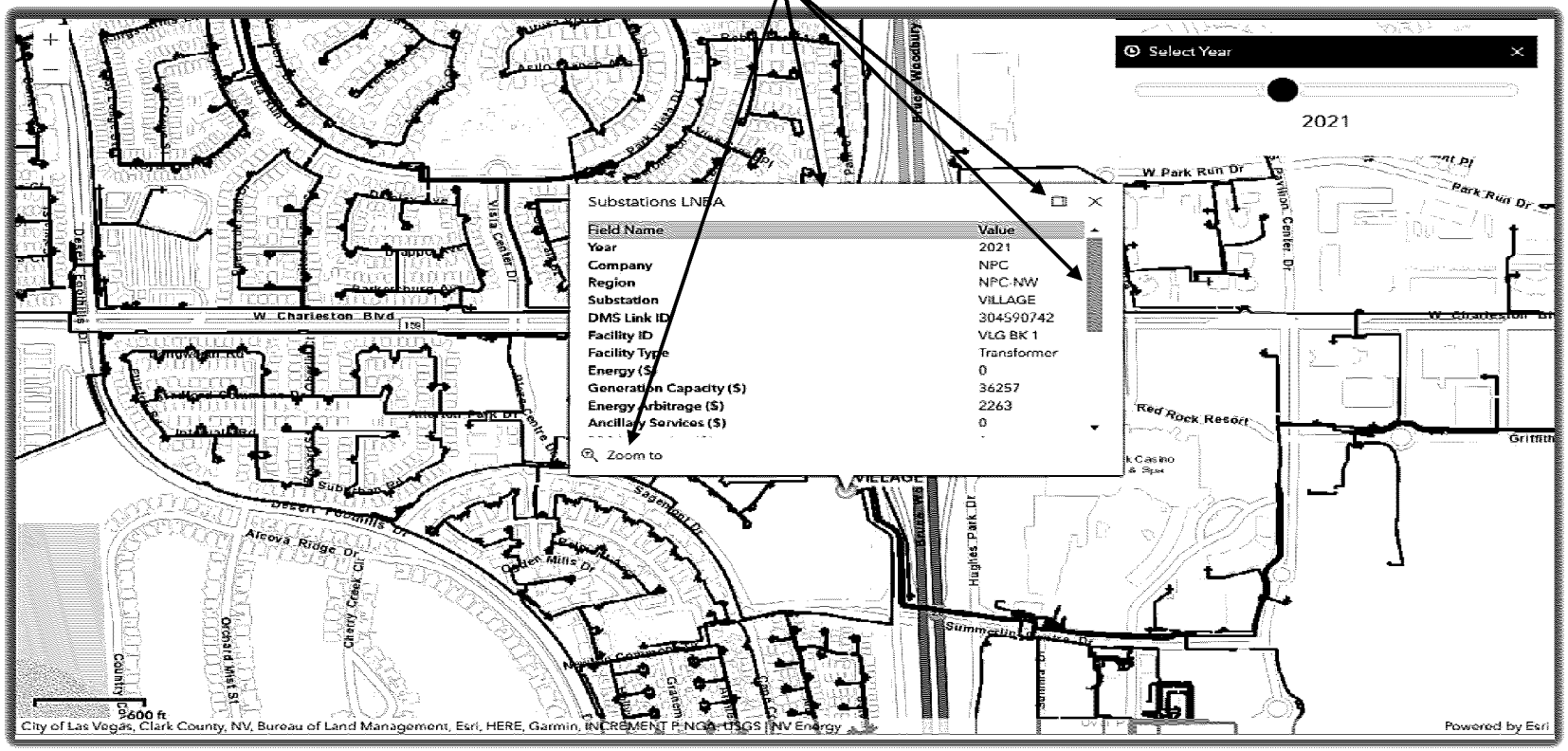
*When the user clicks on **Summary Table**, a Zip file containing the requested download file appears in the upper right of the screen. The file can either be opened by clicking **Open File**, or the user's "Downloads" folder can be accessed. The data file will reside within the Zip file that has been placed in the user's "Downloads" folder. The **Summary Table** data file is in .xlsx format.*



This popup box will appear if there is no file available for download.

Popup Box Information

*Click on any green- or amber-colored substation or feeder section to reveal a popup box that provides detailed LNBA information about the distribution facility. The substation or feeder section will be highlighted in blue. Scroll down in the popup box to reveal the remaining data. The field names are defined below. Click on **Zoom to** to zoom into the selected item. Click on the **Dock** icon to dock the popup box on the top right corner of the screen as you pan to different locations or zoom.*



LNBA Popup Box Field Name and LNBA Summary Table Column Definitions:

Year *– The year that the constraint on the distribution system first occurs, or the year in which NV Energy plans to mitigate the constraint.*

Company *– The territory in which the constraint is forecasted to occur; either NPC or SPPC.*

Region *– The region within NV Energy's territory in which the constraint is forecasted to occur. There are five regions designated in the Nevada Power Company territory: NVE-NE (Northeast), NVE-NW (Northwest), NVE-SE (Southeast), NVE-SW (Southwest), and NVE-Strip (Las Vegas Strip area). There are three regions designated in the Sierra Pacific Power Company territory: SPPC-TM (Truckee Meadows), SPPC-NE (Northeast), and SPPC-NW (Northwest).*

Substation *– The name of the substation in which the constrained distribution system facility is located or is served from.*

DMS Link ID *– The unique identifying number for the feeder section in NV Energy's electronic mapping system.*

Facility ID *– The unique identifier for the constrained distribution system facility, which begins with either a two- or three-character abbreviation for the substation, the abbreviation "BK" if the facility is a substation transformer, and a number identifying either the position of the substation transformer in the substation or the feeder breaker number if the facility is a distribution feeder. The symbol "//" means that two substation transformers are normally operated in parallel with each other.*

Facility Type *– The type of constrained distribution facility (e.g., transformer or feeder).*

Energy ($) *– The value of avoided energy based upon hourly energy prices as estimated by production cost simulation software.*

Generation Capacity ($) *– The value of the avoided additional generation needed at peak demand as determined by optimal dispatch of resources.*

Energy Arbitrage ($) *– The value of the avoided additional generation needed based upon yearly production costs as estimated by production cost simulation software based upon utilization of a 25 MW/100 MWh (4 hour) battery.*

Ancillary Services ($) *– The value of avoided ancillary services requirements (e.g., frequency control, reactive power, operating reserves) as estimated by production cost simulation software. This value is not yet calculated.*

RPS Integration ($) *– The value of avoided costs associated with resource intermittency and uncertainty that must be managed on the power system. Such costs include, but are not limited to, frequency response, voltage regulation, and operating reserves.*

GHG Emissions ($) *– The value of avoided costs associated with the emission of any gaseous compound in the atmosphere that is capable of absorbing infrared radiation, thereby trapping and holding heat in the atmosphere. This value is not yet calculated.*

Transmission Upgrade Estimated Cost ($) *– The estimated cost in today's dollars for the approved traditional transmission capital upgrade project planned to address the constraint.*

Transmission NWA Capacity (kW) *– The total capacity of the NWA (DER-type) solution portfolio in kW resulting from the NWA analysis that would address the transmission constraint.*

Transmission Upgrade Deferral Value ($/kW) *– The value in $/kW of the deferral of a transmission capital upgrade or asset replacement project, calculated as the Transmission Upgrade Estimated Cost / Transmission NWA Capacity.*

Distribution Upgrade Estimated Cost ($) *– The estimated cost in today's dollars for the approved traditional distribution capital upgrade project planned to address the constraint.*

Distribution NWA Capacity (kW) *– The total capacity of the NWA (DER-type) solution portfolio in kW resulting from the NWA analysis that would address the distribution constraint.*

Distribution Upgrade Deferral Value ($/kW) *– The value in $/kW of the deferral of a distribution capital upgrade or asset replacement project, calculated as the Distribution Upgrade Estimated Cost / Distribution NWA Capacity.*

Transmission Upgrade OMAG ($) *– The value of the incremental OMAG associated with a transmission capital upgrade or asset replacement project.*

Distribution Upgrade OMAG ($) *– The value of the incremental OMAG associated with a distribution capital upgrade or asset replacement project.*

T and D Losses ($) *– The value of any estimated reduction in losses on the transmission and distribution systems. This value is not yet calculated.*

Reliability Power Quality ($) *– The value of any quantifiable improvement in the reliability or resiliency of the transmission or distribution system, and potentially providing voltage support to the system. This value is not yet calculated.*

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A/ NV ENERGY** in Docket No. 23-09___ upon the persons listed below by electronic mail:

Don Lomoljo
Public Utilities Comm. of Nevada
1150 E. William Street
Carson City, NV 89701-3109
dlomoljo@puc.nv.gov

Staff Counsel Division
Public Utilities Comm. of Nevada
9075 West Diablo, Suite 250
Las Vegas, NV 89148
pucn.sc@puc.nv.gov

Attorney General's Office
Bureau of Consumer Protection
100 N. Carson St.
Carson City, NV 89701
bcpserv@ag.nv.gov

Attorney General's Office
Bureau of Consumer Protection
8945 W. Russell Road, Suite 204
Las Vegas, NV 89148
bcpserv@ag.nv.gov

DATED this 1st day of September, 2023.

/s/Ashleigh Dennis
Ashleigh Dennis
Regulatory Operations Analyst
Nevada Power Company
Sierra Pacific Power Company