BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Investigation regarding resource adequacy and planning to ensure that electric utilities' supply of energy is sufficient to satisfy demands and maintain reliable, continuous service.	))))	Docket No. 20-08014

REPORT ON ENSURING THAT ELECTRIC UTILITIES' SUPPLY OF ENERGY IS SUFFICIENT TO SATISFY DEMANDS AND MAINTAIN RELIABLE, CONTINUOUS SERVICE

Table of Contents

I. INTRODUCTION

The Public Utilities Commission of Nevada ("Commission") opened an investigation and rulemaking to ensure reliable electric service in Nevada by having an open and transparent look at the constraints experienced during the week of August 17, 2020. These constraints resulted in the reliability coordinator, RC West, declaring an Energy Emergency Alert ("EEA") level 2 and 3 to Nevada Power Company d/b/a NV Energy ("NPC") and Sierra Pacific Power Company d/b/a NV Energy ("SPPC," together with NPC, "NV Energy"), requiring NV Energy to issue a public request for conservation to avoid firm load shedding.

On September 17, 2020, the Commission issued a Notice of Investigation and Rulemaking. On December 16, 2020, the Presiding Officer held a workshop to discuss submitted comments and ask additional questions. NV Energy; Shell Energy North America (US) L.P. ("Shell"); Nevada Gold Mines LLC; Great Basin Transmission, LLC ("GBT"); Tenaska Power Services Co. ("Tenaska"); MGM Resorts International ("MGM"); Caesars Enterprise Services, LLC ("Caesars"); Switch; Wynn Resorts; the Nevada Bureau of Consumer Protection ("BCP"); and the Regulatory Operations Staff of the Commission ("Staff") appeared at the workshop. The Presiding Officer requested that NV Energy provide follow-up comments addressing certain questions that arose during the workshop.

II. SUMMARY

During the month of August 2020, the Western Interconnection experienced significant energy demands due to an extreme heatwave that encompassed the entire western United States. The California Independent System Operator Corporation ("CAISO") instituted rolling blackouts on August 14 and 15, 2020. Entities throughout the Western Interconnection, including NV Energy, joined with the CAISO to provide voluntary transfers in the energy imbalance market ("EIM") and emergency transfers.[1] Just days later, many load-serving entities ("LSEs") throughout the Western Interconnection, including NV Energy, experienced multiple level 2 or higher EEAs due to insufficient generation and transmission capacity to meet peak demand and last-minute changes by the CAISO to its wholesale energy markets. These constraints led to RC West declaring an EEA1 for NV Energy at 12:27 on August 18, 2020, and upgrading to an EEA3 at 15:30. For a ten-hour period on August 18, 2020, NV Energy procured 19,760 megawatt-

[1] "Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave." January 12, 2021, at 49. http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

hours ("MWh") of energy through bilateral contracts with third-party entities. However, during this period, only approximately 13,639 MWh of energy were delivered to NV Energy. For the 1800 hour (hour ending 19), NV Energy's most critical period on August 18, 2020, NV Energy procured over 2,000 MWh of wholesale market energy through bilateral agreements to be delivered but only received approximately 864 MWh of energy, resulting in 1,243 MWh (59 percent) of undelivered energy. NV Energy was able to prevent firm load interruption on August 18, 2020, due to reduced electric demand resulting from requests for conservation and through accessing operating reserves provided by reserve sharing agreements with the Northwest Power Pool ("NWPP").

In response, on August 26, 2020, the Commission opened Docket No. 20-08014 to investigate resource adequacy and planning in Nevada. This investigation docket was initiated to understand the strain on the electric grid due to the west-wide heat wave and ensure Nevada has sufficient resources to maintain continuous reliable service. In particular, the investigation and this Report focus on NV Energy, as the primary Commission-jurisdictional electric utility serving the majority of Nevadans. Similarly, many other western state and regional organizations undertook their own investigations to determine the cause, effect, and necessary changes in their region or state due to the heat-wave event in August 2020.

Although much of resource planning is a long-term exercise, the investigation initially began gathering information from interested persons with both short- and long-term considerations. NV Energy was encouraged to consider any actions it should be taking immediately for the summer of 2021; as a result, NV Energy proposed several changes to its energy supply plan and resource procurement for the summer of 2021.[2] These short-term changes are intended to recognize the strain that hotter-than-normal weather places on the electric grid. The changes also recognize the risk of Nevada's reliance on market resources that are sourced from or wheeled through the CAISO and, therefore, propose procurement of energy at higher targets for reliability purposes. Summer 2021 is upon us, and there remain concerns that another heat wave in the western United States will again put a heavy strain upon the Western Interconnection.[3]

Based on analysis of the areas of concern raised by participants in the investigation, multiple areas that affect resource adequacy were identified. This Report outlines five integrated subject areas of investigation. The five areas are as follows: energy supply planning and load forecasting; balancing authority transmission system operations and related issues; wholesale market considerations for planning; demand response opportunities; and utility information dissemination and communications process. This Report summarizes the information gathered to date and recommends further investigation, with specific recommendations to move Nevada towards ensuring reliable, accessible resources.

Several points evolved through the investigation. Over the prior five years, Nevada's resource planning process has focused on cost-saving opportunities for ratepayers by finding prudent NV Energy's actions to fulfill an increasing amount of its supply needs in the western

[2] Docket No. 20-12020 and Docket No. 21-04036.
[3] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf; https://www.ferc.gov/media/2021-summer-energy-market-and-reliability-assessment

market.[4] This result is due, in part, to a variety of uncertainties over the same period relating to Nevada's energy policy.[5] At the same time, a number of areas of the Western Electricity Coordinating Council ("WECC") faced growing resource constraints. As retirements of large generating stations continue and are replaced by generating resources with dissimilar generating characteristics, some regions in the WECC are growing more dependent on seasonal or intraday imports. Nonetheless, Nevada's planning process, and market and risk assessments, have remained largely unchanged. The WECC's recent assessment of resource adequacy in the West showed that several regions require imports to ensure electric reliability, including Nevada's own region.[6] Nevada can control its generating resources and have simple confidence in its reliability, or Nevada can continue to integrate with the Western Interconnection, understanding that that integration requires NV Energy and the Commission to implement more sophisticated assessment, planning, and monitoring to achieve reliability goals. The first section of this Report discusses Nevada's current resource planning paradigm and begins a discussion to move into the more regional and integrated future.

In the late 1990s, the CAISO was created to operate most of California's transmission system. Although the CAISO must meet federal requirements to provide non-discriminatory access to transmission, the CAISO is not a western regional planning entity; it was structured to meet California's electricity needs.[7] However, because the CAISO is the only liquid market in the West, all trades between Balancing Authorities ("BAs") or utilities are either bilateral transactions or traded volumes in the CAISO markets (the Day-Ahead Market ("DAM") and sometimes Day of Market or EIM). Bilateral trades between buyers and sellers are consummated using "Western States Power Pool ("WSPP") Schedule C" contracts which are "firm" power supply contracts financially backed by liquidated damage provisions in the WECC, which are financial reparations for non-performance but do not provide for the physical replacement or delivery of contracted energy.[8] However, a downstream buyer has no way of distinguishing between a Schedule C contract backed by a portfolio of physical generation owned by the seller and a "firm" contract backed by day-ahead purchases in the CAISO markets. Therefore, buyers of "firm" Schedule C power in WECC are generally subject to the market and curtailment rules imposed by the CAISO on traders, exporters, and other market participants that buy from, sell in, or wheel power through the CAISO.

Although the Commission's investigation is not complete, NV Energy's EEA3 on August 18, 2020, was partially a result of undelivered wholesale energy procured through firm, bilateral agreements executed by NV Energy and other Nevada Network Integration Transmission Service ("NITS") Customers. NV Energy procures energy and/or capacity in the wholesale energy market through bilateral agreements and participates in the CAISO's EIM to ensure its resource adequacy. NV Energy has issued requests for proposals for non-CAISO-sourced

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[4] Docket Nos. 16-07001, 16-08027, 18-06003, and 19-06039 saw an increase in NV Energy's 2020 summer open position. These dockets also approved the addition of many purchased power agreements to NV Energy's portfolio with deliveries in 2021 and further, but no new supply-side generating resources.
[5] The Energy Choice Initiative and the rapid pursuit of NRS 704B by dozens of NV Energy's largest customers. Cited in Docket Nos. 16-07001 and 16-08027 by the Commission.
[6] The Western Assessment of Resource Adequacy Report," December 18, 2020. https://www.wecc.org/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2020201218.pdf
[7] http://www.caiso.com/rules/Pages/Regulatory/Default.aspx
[8] Contractual liquidated damages are small comfort to NV Energy customers when an EEA event is declared.

energy,[9] but because the CAISO is the largest and only liquid market in the western United States, NV Energy currently relies on the CAISO wholesale energy market for a portion of its resource adequacy to provide reliable electric service to Nevadans. Compounding this reliance, following the Commission's decision in several Nevada Revised Statutes ("NRS") 704B cases in 2015, the providers of new electric resources of Nevada's distribution-only service ("DOS") customers are serving those customers through market purchases and do not have generating resources. [10] These providers access the same market for their resources via bilateral agreements, typically the same Schedule C contract or other similar financially-backed agreements.

A western electric region increasingly tight on resources, a growing reliance on a market that is interconnected through California, a limited ability to ascertain the physical generation backing some sales and their potential deliverability, and an ever-rising number of market participants competing for the same resources worked in combination until excessive temperatures caused demand to rise to unexpected levels. This is the perfect storm that arrived in Nevada in August 2020.

The West as a region and Nevada as a state need a larger, regional market that integrates multiple utilities allowing renewable generating resources to balance across large geographic areas.[11] A predictable, reliable western transmission system is critical to ensuring electric reliability in the region. Today, Nevada often exports solar generation and relies on imports from neighboring states like California, Arizona, and Oregon to meet peak demand, particularly during the evening when solar generation is unavailable. This particular exercise must become more granular and move beyond the borders of Nevada and lengthen its focus to assess regional market risks. Sections V. B. and V. C. of this Report provide an assessment in these areas: balancing authority transmission system operations and related issues and wholesale market considerations for planning. Although Nevada has engaged in robust resource planning for several decades, it is time to expand NV Energy's planning to consider its responsibility for the Balancing Authority Area ("BAA"), its connectivity within the Western Interconnection, and the reliability of western markets as part of the integrated resource plan.

In addition, climate data trends suggest heat events that are hotter, more frequent, and later in the summer.[12] Beyond planning for the resources to adequately serve customers, it is necessary for NV Energy to prepare to best dispatch its electric system in cooperation with its customers when the challenging grid conditions arrive. Sections V. D. and V. E. of the Report review both NV Energy's demand response programs and its information dissemination and communications process. The good news is that demand response worked in August 2020 to

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[9] NV Energy issued an RFP for non-CAISO sourced energy for Summer 2021, and was able to only secure one bilateral agreement for 250 MW.

[10] Docket No. 15-05017, Order on Reconsideration dated January 20, 2016, at paragraph 20, page 10; and Modified Final Order dated January 20, 2016 at paragraph 230, page 78.

[11] "Increasing the size of the geographic area over which the wind and solar resources are drawn substantially reduces variability." NREL https://www.nrel.gov/grid/wwsis.html

[12] Romero-Lankao, P., J.B. Smith, D.J. Davidson, N.S. Diffenbaugh, P.L. Kinney, P. Kirshen, P. Kovacs, and L. Villers Ruiz, 2014: North America. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1439-1498; *See also* https://climate.nasa.gov/effects/.

lower demand during a critical period, and this data will be vital in evaluating future demand-side management program offerings. Significantly, this Report indicates that NV Energy has some work to do in the final area: ensuring NV Energy has in place a comprehensive, transparent, and readily-executable plan for communicating with its customers during stressed conditions.

The electric grid in Nevada is a very complicated apparatus. As NV Energy's customer demand increases and energy policy changes to adapt to climate concerns, the tools for ensuring reliable electric service must also adapt. This Report is the first in many steps to move Nevada toward assessing what changes may be needed to assure our resource adequacy goals.

III. BACKGROUND

A. An Overview of the Electric System in Nevada

Nevadans receive their electricity from NPC or SPPC,[13] private investor-owned utilities ("IOUs"), or from one of the municipal or rural power districts across the state.[14] These electric utilities generally maintain a monopoly franchise, meaning that there is usually only one utility for any geographical area. The transmission system is connected to power plants that generate the electricity powering Nevadans' homes and businesses.[15] Some large industrial customers, such as remote mines, are directly connected to the transmission system. These customers can purchase power or own generation and have that power delivered to their location via the transmission system.

In Nevada, large commercial and industrial electricity customers are permitted to purchase or generate their own electricity and use transmission lines and lower-voltage distribution lines to deliver power to their locations. In Nevada, only large industrial and commercial customers can "unbundle" transmission and distribution from electricity itself and purchase DOS separately while self-supplying their own power. Whether a customer's power is bundled with transmission for delivered service or unbundled into separate services and charges, at its simplest, the power system looks like this:[16]

Figure 1 – The North American electric grid is one of the most complex machines ever built so there are many more stakeholders, operations, and interactions than this simple four-part illustration can convey.

[13] Map of NV Energy service territory: https://puc.nv.gov/uploadedFiles/pucnvgov/Content/Utilities/NV_Energy_Service_Areas.pdf
[14] Map of rural utilities: https://puc.nv.gov/uploadedFiles/pucnvgov/Content/Utilities/Nevada_Rural_Utility_Service_Areas.pdf
[15] The exception is Valley Electric which is interconnected with California's transmission system and is thus in the California Balancing Authority Area.
[16] Department of Energy, Office of Energy Policy and Systems Analysis, 2016

NV Energy owns and operates the transmission system in Nevada. Thus, all electric utilities in Nevada are also customers of NV Energy transmission service, which is regulated by the Federal Energy Regulatory Commission ("FERC"), and are located in NV Energy's BAA.[17] NV Energy must ensure that the amount of electricity being put onto its transmission lines matches the amount that users or "load" demand from the system at all times. In this way, the BAA coordinates all of the transmission system users, much like an air traffic controller might manage all of the planes landing, taking off, and taxiing at an airport.[18]

In addition to the BAA covering most of Nevada,[19] the state's utilities are integrated into regional electric networks. First, NV Energy is a member of the NWPP,[20] a voluntary organization comprised of major generating utilities servicing the Northwestern United States and Western Canada, including electric utilities in Washington, Oregon, Idaho, Utah, and Nevada, as well as parts of California, Wyoming, Montana, and the province of British Columbia. NWPP allows neighboring utilities to share resources and do some limited joint, regional planning.[21] The entire NV Energy BAA is also part of the Western Interconnection, which encompasses the western third of the continental United States (excluding Alaska), the Canadian provinces of Alberta and British Columbia, and a portion of Baja California Norte, Mexico.[22]

The rest of the US is divided into the Eastern Interconnection, which is connected to parts of Eastern Canada,[23] and Texas, which operates its own electrically-separate grid. Each of these Interconnections is electrically separate. Making sales and purchases of power across the country is largely limited to the Interconnection where a utility is located.

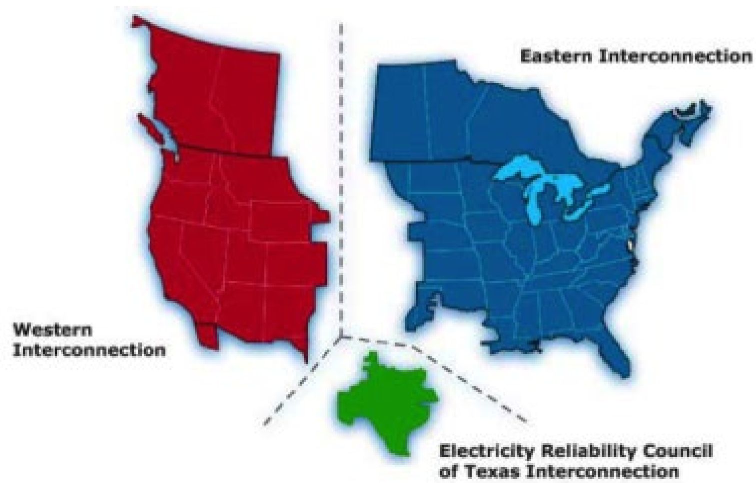

Figure 2 – Division of Interconnection in the United States.

The North American Electric Reliability Corporation ("NERC") has authority over the various entities described above. NERC sets electric reliability standards for the Interconnections and their constituent BAAs and utilities to meet, such as tree trimming near transmission lines to reduce contact risks or cybersecurity standards to prevent hacking from damaging generators.[24] NERC is empowered via the Energy

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[17] A BAA is the geographic area, connected by transmission, where a utility must keep electric generation and load (demand for power) in balance.
[18] There are over 100 balancing authorities across the United States.
[19] As mentioned above, Valley Electric is part of California's BAA.
[20] https://www.nwpp.org/news/map-of-nwpp-ra-footprint
[21] https://www.nwpp.org/
[22] https://www.wecc.org/Pages/home.aspx.
[23] Note: In 2006, the Canadian Province of Québec's transmission system was recognized as a separate interconnection because it is not synchronized with neighboring systems; https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/NERC_Interconnection_1A.pdf.
[24] https://www.nerc.com/AboutNERC/Pages/default.aspx

Policy Act of 2005[25] to require registration of and impose reliability standards on a suite of stakeholders.[26]

The FERC, which oversees NERC, is an independent arm of the Department of Energy that serves as the regulator of transmission in interstate commerce, sales for resale of electricity, and interstate natural gas operations and markets. FERC enforces NERC reliability standards and monitors energy markets to ensure robust, fair wholesale energy markets.[27] Similarly, state commissions, including the Commission, regulate intrastate retail electric transactions and operations.

Notably, these organizational and regulatory institutions evolved before new technologies and market patterns added to the complexity of grid operations. With the advent of electric storage, rooftop solar generation, electric vehicles, and other technologies, the electric grid increasingly operates in both directions with consumers selling rooftop power back to the utility one hour and buying power the next. The grid and planning for how to operate it has also grown more complex as many of the new renewable resources are variable, *e.g.*, the sun does not always shine on solar panels. Utilities, BAAs, and power pools must update their planning processes to account for new technologies. These innovations bring both challenges with intermittency and benefits with demand flexibility, as more customers have "behind-the-meter" resources that can be dispatched to help balance the grid, including demand response, battery storage, and even electric vehicles ("EV"). Consequently, the modern grid now looks something more like this:[28]

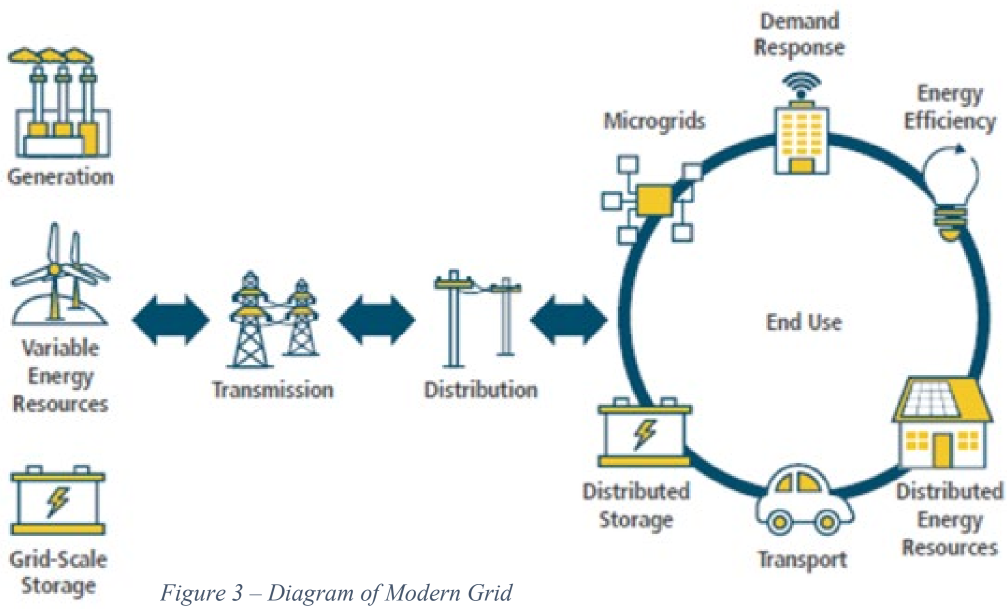

Figure 3 – Diagram of Modern Grid

[25] Enforcement Reliability | Federal Energy Regulatory Commission (ferc.gov)
[26] NERC identified the following twelve reliability functions, necessary for the reliable operation of the electric grid: Reliability Coordinator (RC); Balancing Authority (BA); Planning Authority (PA); Transmission Planner (TP); Transmission Operator (TOP); Transmission Service Provider (TSP); Transmission Owner (TO); Resource Planner (RP); Distribution Provider (DP); Generator Owner (GO); Generator Operator (GOP) and Reserve Sharing Group (RSG)
[27] https://ferc.gov/about/what-ferc/what-ferc-does
[28] Figure S-3 Quadrennial Energy Review 1.2 2017 US DOE; Department of Energy, Office of Energy Policy and Systems Analysis, 2016.

B. Integrated Resource Plan ("IRP") and Energy Supply Plan ("ESP") Framework

IRP Overview

Every three years, an electric utility is required to file an integrated resource plan with the Commission to increase its supply of electricity or decrease the demands customers make on its system.[29] The IRP sets forth a three-year action plan to meet demand for electric service in an efficient, reliable, and sustainable manner over a 20-year planning period.[30] The Commission is charged with developing the contents of the IRP, including, but not limited to, the methods or formulas which are used by the utility to: (1) forecast the future demands; and (2) determine the best combination of sources of supply to meet the demands or the best method to reduce the demands.[31]

Any assumptions, forecasts, conclusions, and information used by an electric utility in its IRP must be: (1) based on substantially accurate data; (2) adequately demonstrated and defended; and (2) adequately documented and justified. Electric utilities must conduct a sensitivity analysis for any major assumptions used in the IRP, state the ranges and consequences of uncertainty for each of the assumptions, and describe methods of combining various uncertainties. In the IRP, electric utilities must analyze decisions, considering the assessment of risk and identifying particular risks with respect to: (1) costs; (2) reliability; (3) finances; (4) the volatility of the price of purchased power and fuel; and (5) other uncertainties identified. An IRP must consist of and provide an integrated analysis of (1) a load forecast; (2) a demand-side plan; (3) a supply plan; (4) a financial plan; (5) an energy supply plan; (6) a distributed resources plan; and (7) a three-year action plan. The load forecast, supply side plan, action plan (a detailed specification of the action the utility intends to take to meet its demand and energy requirements during the three-year period immediately following the year in which the utility files the IRP), and energy supply-side plan detail an electric utility's resource adequacy. An electric utility's resource adequacy is determined by comparing capacity of its available supply-side resources to its forecasted required total capacity. When the capacity of a utility's supply-side generating resources is less than its forecasted required total capacity, a utility is resource-inadequate, and an amount of additional capacity, referred to as an open position, needed for a utility to reach resource adequacy is identified.

After a hearing on an IRP, the Commission must issue an order accepting, modifying, or deeming inadequate the utility's plan. The Commission must determine, among other factors, whether: (1) the forecasted requirements of the utility are based on substantially accurate data and an adequate method of forecasting; (2) the plan identifies and accounts for reductions in the demand for energy associated with energy efficiency programs;[32] and (3) the plan adequately demonstrates the economic, environmental, and other benefits associated with energy efficiency,

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[29] NRS 704.741(1) NRS 704.741 through 704.751 provides the statutory framework for triennial electric utility IRPs in Nevada.

[30] The Commission-adopted IRP and ESP regulations are in NAC 704.9005 through 704.9525.

[31] NRS 704.741(1-2)

[32] Nevada's legislated energy policy requires the Commission to give preference to the DSM measures and sources of supply that (1) provide the greatest economic, employment, and environmental benefits to Nevada; (2) provide levels of service that are adequate and reliable; and (3) provide for a diverse resource portfolio that reduces customer exposure to the price volatility of fossil fuels and the potential costs of carbon associated with fossil fuels. NRS 704.746(5)

power pooling, market purchases, renewable energy, and other generation and transmission facilities. [33]

Load Forecast

The load forecast for peak demand and energy consumption must represent the range of future load that the electric utility's system may be required to serve over a 20-year forecast period, beginning the year in which the IRP is filed, including scenarios of low, base, and high economic growth and demographic change.[34] The base load forecast represents the most likely set of future conditions or forces which would have an effect on peak demand and energy consumption, while the low and high load forecasts represent the lowest and highest rate of population and economic growth, respectively.[35] The load forecast must be normalized (adjusted to reflect normal or representative variable conditions) to account for normal weather conditions within the electric utility's service territory.[36]

Supply-Side Plan Overview

The supply-side plan is an electric utility's plan for using existing and proposed resources to meet its forecasted demand and energy requirements of the 20-year period. In the supply-side plan, an electric utility must develop and document the origins of: (1) the assumptions, data, and projections used by the utility to calculate the costs and benefits of its options; (2) the assessment of current and anticipated electric market conditions for the region in which the utility operates; (3) the criteria used by the utility for determining the planning reserve margin; and (4) a list of all of the sources and amounts from which a utility has contracted to buy, or has plans or potential opportunities to buy, electric power during the 20 years covered by the supply side plan.[37]

An electric utility must identify its preferred plan and provide a diverse set of alternative plans that list the options for supply of capacity and electric energy and other resources available for the utility to meet its future peak demand.[38] Additionally, an electric utility must develop a set of analyses of its supply-side options to be considered for meeting its forecasted peak demand.[39] The analyses must include power pooling, power purchase, and power exchange transactions with other utilities and independent producers.[40]

ESP Overview

The energy supply plan ("ESP"), consisting of a purchased power procurement plan, fuel procurement plan, and risk management strategy, establishes the parameters for the energy supply portfolio of the utility during the three-year action plan which balances the objectives of (1) minimizing the cost of supply; (2) minimizing the retail price volatility; (3) and maximizing

[33] NRS 704.746(4)
[34] NAC 704.9225(1)
[35] NAC 704.9075, NAC 704.9085 and NAC 704.909
[36] NAC 704.9135 and NAC 704.9245
[37] The list does not contain every requirement outlined in NAC 704.9385.
[38] NAC 704.937
[39] NAC 704.9355
[40] NAC 704.9355

the reliability of energy supply over the term of the ESP.[41] The ESP must be based upon the utility's base forecast and target planning reserve margin.[42]

The purchased power procurement plan balances the objective of minimizing costs and price volatility of purchased power and maximizing the reliability of purchased power during the ESP period.[43] The fuel procurement plan in the ESP balances the objective of minimizing costs and price volatility of fuel and maximizing the reliability of fuel supply during the ESP period.[44] The risk management strategy is the systematic method utilized by the utility in the ESP to identify risks inherent in procuring and obtaining a supply portfolio. The risk management strategy also establishes the utility's processes and plans to address and balance, or hedge, the identified risks related to cost, price volatility, and reliability.[45]

For the Commission to make a determination that the elements of the ESP are prudent:[46] (1) the ESP must not contain any feature or mechanism that would lead to a deterioration or impair the restoration of the utility's creditworthiness; (2) the ESP must optimize the value of the overall supply portfolio for the benefit of the utility's customers; and (3) the utility must demonstrate that the ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing the reliability of supply over the term of the ESP.[47] The utility may deviate from an approved ESP to the extent necessary for adequate response to any significant circumstances not contemplated by the ESP, including without limitation: (1) a material change in the market price of fuel or purchased power; (2) an extended forced outage of a major generating unit; (3) a material change in customer demand; and (4) any other circumstance that the utility demonstrates to the Commission warrants a deviation.[48] If the electric utility deviates from its approved ESP, it must inform Staff as soon as practicable and describe and justify any costs associated with the deviation in the deferred energy application in which the utility requests recovery of the costs.[49]

IV. TIMELINE – AUGUST 2020

The August 2020 events described below occurred in the context of relatively robust projected electric market conditions. As it does before every summer season, the Energy Information Administration ("EIA") released energy market forecasts which projected a low to normal electricity demand forecast for the West.[50] Moreover, the FERC's summer market assessment showed adequate resources available, stating that all NERC Planning Regions appeared to have enough generation available to exceed their reserve margins, except for the

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[41] NAC 704.9061
[42] NAC 704.9482(2)
[43] NAC 704.9153
[44] NAC 704.9099
[45] NAC 704.9157
[46] After a hearing on an IRP, including the supply plan, the Commission must issue an order accepting or modifying the plan, or specifying any portions of the plan it deems to be inadequate. Commission approval of an action plan constitutes a finding that the programs and projects contained in the action plan are prudent.
[47] NAC 704.9494(4)
[48] NAC 704.9504(1)
[49] NAC 704.9504(2)
[50] https://www.eia.gov/todayinenergy/detail.php?id=44055

Electric Reliability Council of Texas ("ERCOT").[51] In Nevada, as more fully described in Section V.A. and summarized below in Table 1, the Commission had approved NV Energy's latest Joint ESP in Docket No. 19-08034, which allowed the utility to procure generation capacity and other resources to meet forecasted demand. Table 1, below, shows the forecasted August peak demand, planned reserves, the conventional and renewable energy generating resources, and market energy that was available to meet that load during the summer cooling period, and it identifies the amount of additional capacity needed (referred to as an "open position") when the ESP was filed with the Commission. Consistent with prior plans, NV Energy's projections did include planned market purchases as well as open positions. Thus, Nevada needed market purchases and imports from other BAAs to meet forecasted summer demand. Based on the projections of NV Energy and federal regulators, the Western Interconnection and Nevada did not enter the summer cooling season unprepared for forecasted demand.

Table 1.	**Aug-20**	**Aug-20**	**Aug-21**	**Aug-21**
NV Energy's Loads and Resources in MWs	2018 ESP 18-06003	2019 ESP Update 19-08034	2020 ESP Additional Update 20-12020	2020 ESP 2nd Additional Update 21-04036
Forecasted Peak Demand	6,701	7,080	7,135	7,135
Planning Reserve Margin	871	903	1,284	1,284
Total Required Capacity	7,572	7,983	8,419	8,419
NV Energy's Generation Capacity	5,736	5,772	5,736	
Purchase Power Agreements	451	677	676	
Renewable Energy	742	542	500	
Market Purchases	-	351	978	
Total Supply Side Resources	6,929	7,342	7,890	
Open Position	643	641	529	

And yet, the entire Western Interconnection did face tight conditions during the heat wave conditions of August 14 – August 20, 2020. Many BAAs and individual utilities in the Western Interconnection had to use most of the resources at their disposal to meet soaring customer demand, leaving little left over to export to neighboring BAAs who would normally be able to import extra electric resources to meet their own demand.

Nevada itself did not face electricity outages like other WECC area BAAs, including California. However, due to the elevated power demand, limited exports within the WECC area, and some generation resource issues, customers in Nevada were asked to conserve power to avoid shortages as described in Section V. E. The timeline below outlines the August 2020 events showing several dimensions of the resource adequacy event from regional weather to the state and regional power system operations, to the customers' experience.

[51] FERC Summer Energy Market and Reliability Assessment. p. 1 https://www.ferc.gov/sites/default/files/2020-06/2020_Summer_Energy_Market_Reliability_Assessment.pdf

	August 14 Friday	August 15 Saturday	August 16 Sunday	August 17 Monday	August 18 Tuesday	August 19 Wednesday	August 20 Thursday
Weather	Temperatures 15-30 degrees above normal	NWS excessive heat warning declared across West	August Complex fire starts 130° Death Valley high		North Complex Fire starts		
Electric System (NVE)	No-touch order declared for all NVE generation equipment		Gonder and Red Butte transmission line outages (NVE noted no impact)	Day-ahead market supply shortages Shortages: 15 hrs at 30 MW>; 4 hrs at 365-506 MW Failed EIM test Mead=$178.60 NVE Peak 32% Higher than 4th IRP Amendment Forecasted Peak	Valmy +127 MW 4pm: 95 MW short of reserves 7pm: 1,243 MW imports curtailed Mead=$1,300 8 DOS & 4 FERC customers 5%-100% short for 1 hour+ 4pm peak: 7,780 MW NVE Peak 36% Higher than IRP Forecast Peak	Valmy +127 MW Unit 1 cap Mead=$1,380/ MWh Voluntary conservation requests NVE Peak 58% Higher than IRP Forecast Peak	Mead= $211.76/ MWh NVE Peak 70% Higher than IRP Forecast Peak
Electric System (WECC)	Low wind production; 2 CAISO load shedding events	2 BA EEAs	1 BA EEA	4pm WECC hit demand record of 162,017 MW 6 BA EEAs	NVE imports NWPP reserves (5-9pm) RC West declares NVE EEA3 (3:30pm) then EEA1; EEA0 (9:31pm)	2 BA EEAs RC West declares NVE EEA1 (12:27pm); EEA0 (7:20pm)	
People			Smoke from record wildfires impacts air quality <-->		178 MW of NVE DR called Conservation calls 2-9pm	Conservation calls 2-9pm	

Table 2. Event Timeline.

V. INVESTIGATION FINDINGS

A. Energy Supply Planning and Load Forecasting

Introduction

Energy supply planning and load forecasting are integral pieces of resource adequacy planning. The Commission has identified several areas of concern after analyzing NV Energy's load forecasting data. First, NV Energy's long-term hourly load forecasting may have a high percentage of error. Second, it is not clear to the Commission what processes and procedures NV Energy uses to monitor and adjust its long-term load forecasting assumptions after internal approval. Finally, it may be necessary to update the Commission's regulations following NV Energy's 2021 IRP filing.

Background on the Currently-Approved IRP and ESP for NV Energy

NV Energy's 2018 IRP

NV Energy filed its triennial IRP for the three-year action plan period 2019-2021 and ESP period 2019-2021 in June 2018 in Docket No. 18-06003. In its ESP, NV Energy forecasted a total capacity requirement of 8,252 MW, which includes a 13-percent planning reserve margin in July 2020, and an open capacity position of 1,314 MW—1,046 for NPC and 256 MW for SPPC.[52] For August 2020, NV Energy forecasted a peak load of 6,701 MW with a planning

[52] Docket No. 18-06003, Volume 18, Figure ESP-4B at page 123 of 361.

reserve margin of 13 percent, or 871 MW, totaling 7,572 MW of required capacity. [53] NV Energy's available supply-side resources totaled 6,929 MW for August 2020, leaving an open position of 643 MW—513 MW for NPC and 133 MW for SPPC.[54] NV Energy proposed implementing a four-season laddering strategy for procuring capacity in the wholesale market to close its summer 2020 open position because of previous EEA reliability events affecting neighboring BAAs in the Western Interconnect.[55] Under the laddering strategy, NV Energy would procure 25 percent of its open capacity, updated internally by NV Energy as needed, per quarter starting with the third quarter of 2018 and ending in the first quarter of 2020.[56] Therefore, by the end of Quarter 1 2020, NV Energy would have acquired enough capacity and energy to meet its forecasted peak summer 2020 load and its 13-percent planning reserve margin.

On October 12, 2018, the Commission accepted a stipulation and granted approval of NV Energy's ESP and load forecast as modified by the stipulation. In the stipulation, the parties agreed that the long-term load forecast was suitable for making planning decisions through the ESP period 2019-2021 and that the ESP as presented by NV Energy balanced the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing reliability over the term of the plan; and that the elements of the ESP were prudent.

NV Energy's 2019 ESP Update

On August 30, 2019, NV Energy filed its ESP Update for the period 2020-2021 in Docket No. 19-08034. In its 2019 ESP Update, NV Energy forecasted a total required capacity of 8,664 MW, which includes a 13 percent planning reserve margin in July 2020 with an open position of 1,101 MW – 870 MW for NPC and 231 MW for SPPC.[57] For August 2020, NV Energy forecasted a peak load of 7,080 MW and a 13-percent planning reserve margin of 903 MW, totaling 7,983 MW of required capacity.[58] NV Energy's supply-side resources totaled 7,563 MW, leaving an open position of 641 MW—430 MW for NPC and 211 MW for SPPC.

NV Energy's 2019 ESP purchased power plan continued the laddering strategy approved in its 2018 ESP. On November 14, 2019, the Commission accepted a stipulation and granted approval of NV Energy's ESP, as modified by the stipulation. In the stipulation, the parties agreed that the load forecast was suitable for making two-year planning decisions during the ESP Update period 2020-2021 and that the ESP as presented by NV Energy balanced the objectives of minimizing the cost of supply, minimizing retail price volatility, and maximizing reliability over the term of the plan; and that the elements of the ESP were prudent. NV Energy's 2019 ESP Update load forecast was the most recent Commission-approved load forecast before the summer of 2020.

NV Energy's 4th IRP Amendment

On July 20, 2020, NV Energy filed its 4th IRP Amendment in Docket No. 20-07023. In its 4th IRP Amendment, NV Energy forecasted a system peak demand of 6,959 MW and a 13-percent planning reserve margin of 886 MW, totaling 7,845 MW of required capacity for August

[53] Docket No. 18-06003, Volume 18, Figure ESP-4B at page 123 of 361.
[54] Docket No. 18-06003, Volume 18, Figure ESP-4B at page 123 of 361.
[55] Docket No. 18-06003, Volume 18, Narrative at page 176 of 361.
[56] Docket No. 18-06003, Volume 18, Figure ESP-25 at page 177 of 361.
[57] Docket No. 19-08034, Volume 1, Figure ESP-4A at pate 135 of 206.
[58] Docket No. 19-08034, Volume 1, Figure ESP-4A at pate 135 of 206.

2020.[59] NV Energy's supply-side resources totaled 7,992 MW, resulting in a long capacity position of 147 MW. NV Energy initially prepared the load forecast for its 4th IRP Amendment in February 2020 but, due to NV Energy's anticipated demand reductions and uncertainties with the COVID-19 pandemic, it revised the load forecast in April 2020.[60] NV Energy's 4th IRP Amendment load forecast was internally approved at NV Energy's April 2020 Risk Committee meeting, which NV Energy used to plan for summer 2020.[61] The Commission had not issued an order regarding NV Energy's 4th IRP Amendment load forecast prior to the events of August 2020.

NV Energy's long-term load forecast data filed with the Commission on October 5, 2020, includes the overall forecasted peak load, the forecasted hourly loads, and the forecasted daily system peak. A review of these components indicates that, while the overall forecast was slightly high, the hourly and daily forecasts were significantly understated. The load forecast data shows that NV Energy's actual peak load during the week of August 17, 2020, was between 3 percent and 16 percent lower than the August 2020 forecasted peak in NV Energy's 2019 ESP Update and between 1 percent and 15 percent lower than the August 2020 forecasted peak in NV Energy's 4th IRP Amendment. Additionally, NV Energy's actual hourly loads during the week of August 17, 2020, were between 6 percent and 48 percent higher than forecasted in NV Energy's 2019 ESP Update and between 16 percent and 73 percent higher than forecasted in NV Energy's 4th IRP Amendment. Furthermore, NV Energy's actual daily system peaks during the week of August 17, 2020, were between 116 percent and 147 percent higher than forecasted in NV Energy's 2019 ESP Update and between 129 percent and 170 percent higher than forecasted in NV Energy's 4th IRP Amendment. This analysis shows that NV Energy's hourly and daily load forecasting for the week of August 17, 2020, require additional investigation to understand how NV Energy disaggregates its monthly peak load forecast. The tables below provide comparisons of NV Energy's actual system loads to its long and short-term load forecasts.

Percentage Difference Between NV Energy's Actual Monthly August 2020 Peak Load and Forecasted Monthly August 2020 Peak Load

Table 3.	**2019 ESP Update Load Forecast- Filed August 2019**	**4th IRP Amendment Load Forecast - Filed July 2020**
17-Aug	-3	-1
18-Aug	-3	-1
19-Aug	-6	-4
20-Aug	-5	-4
21-Aug	7	-6
22-Aug	-16	-15
23-Aug	-16	-15

[59] NV Energy October 5, 2020, Comments at 7-8.
[60] Docket No 20-07023. Volume 1, Narrative at page 41 of 236.
[61] *Id.*

Percentage Difference Between NV Energy's Daily Actual Peak Load and Forecasted Daily Peak Load

	2019 ESP Update Load Forecast- Filed August 2019	4th IRP Amendment Load Forecast - Filed July 2020	Day-Ahead Load Forecast	Real-Time Load Forecast
17-Aug	120	132	4	0
18-Aug	124	136	4	-1
19-Aug	123	158	-2	-3
20-Aug	142	170	-2	0
21-Aug	147	147	0	-2
22-Aug	123	129	-5	-5
23-Aug	116	130	-6	-1

NV Energy's Hourly Load Forecast Percent Error

	2019 ESP Update Load Forecast- Filed August 2019	4th IRP Amendment Load Forecast - Filed July 2020	Day-Ahead Load Forecast	Real-Time Load Forecast
17-Aug				
Hourly Min	6	16	0	0
Hourly Max	21	35	10	3
Hourly Average	14	27	4	2
18-Aug				
Hourly Min	9	19	0	0
Hourly Max	25	40	10	6
Hourly Average	17	30	5	2
19-Aug				
Hourly Min	10	28	0	2
Hourly Max	25	60	14	12
Hourly Average	17	43	4	5
20-Aug				
Hourly Min	15	26	0	0
Hourly Max	44	73	5	2
Hourly Average	31	51	2	1
21-Aug				
Hourly Min	18	21	0	0
Hourly Max	48	48	8	5
Hourly Average	33	36	2	2

22-Aug				
Hourly Min	12	20	1	1
Hourly Max	29	37	17	7
Hourly Average	21	29	8	5
23-Aug				
Hourly Min	8	18	1	0
Hourly Max	25	43	13	7
Hourly Average	12	25	6	2

Participant Comments

NV Energy's Comments

NV Energy states that it files, as part of its IRP, a long-term load forecast, near-term native and non-native load forecasts, and an ESP. (NV Energy's October 5, 2020, Comments at 2). NV Energy provides that it uses the long-term load forecast in long-term resource planning and the near-term load forecast for the three-year plan periods of the action plan and ESP. (*Id.*) NV Energy further provides that the ESP sets forth NV Energy's power procurement plan, fuel procurement plan, and risk management strategies. NV Energy states that it updates these plans and strategies annually. (*Id.* at 2-3.)

NV Energy states that, in its ESP Update in Docket No. 19-08034, it provided the load forecast for the 2020-2021 planning period and recommended and sought approval of a four-season laddering strategy of both power and gas in its power and fuel procurement plans to ensure adequate resources for summer peak demand. (*Id.* at3.) NV Energy further states that it closed its Summer 2020 open capacity position in the first quarter of 2020. (*Id.*). NV Energy provides that after closing the Summer 2020 open capacity position, it continuously monitored the loads and resources for the summer season and provided regular updates through its risk management committee meetings. (*Id.*) NV Energy states that it procures any additional power or natural gas through day-ahead and real-time trading short-term market purchases because electric loads and generating resources vary each summer month due to weather and other conditions. (*Id.*)). NV Energy states that its Resource Optimization group evaluates the real-time load forecast and adjusts it in the month ahead, day ahead, and in real-time as needed. (Tr. at 121.)

NV Energy states that it made its last triennial IRP filing in June 2018 in Docket No. 18-06003. (*Id.* at 2.) NV Energy states that it provided the Commission with the two most recent load forecasts in the August 2019 ESP Update for the period 2020 – 2021 in Docket No. 19-08034 and in the July 2020 IRP 4th Amendment in Docket No. 20-07023. (*Id.* at 6.) NV Energy states that it internally updated its 7,845-MW peak load and its 7,992 MW of supply-side capacity for August 2020 in its April 2020 Risk Committee for the 2020 IRP 4th Amendment (*Id.* at 7.)

NV Energy states that for the week of August 17, 2020, its actual hourly load exceeded its ESP load forecast every hour of the week for NPC and every hour after 11:00 a.m. every day for SPPC. (*Id.*) NV Energy states that it expected this because the long-term and ESP monthly peak forecasts compare specific calendar day hourly loads to actual loads and the forecasted weather profile across the year is assigned to days based on a previous year and the forecast adjusts the weather profile based on the day of the week through time. (*Id.*) NV Energy provides that, although it is a good proxy for forecasting, it is unlikely that the forecasted weather will be an exact match of the actual weather for most days. (*Id.*) NV Energy states that any differences between the long-term forecast and actual loads for the week of August 17, 2020, is predominantly driven by the difference in the forecasted weather conditions and actual weather conditions. (*Id.*) NV Energy states that the average hourly difference during the week of August 17, 2020, between the long-term forecasts and actuals is approximately 1,200 MW and that the average daily temperatures were approximately 11 and 4 degrees Fahrenheit lower than the actual temperatures for NPC and SPPC, respectively. (*Id.*)

NV Energy states that it typically uses a 20-year weather-normalized load forecast for resource planning. (Tr. at 28-29.) NV Energy states that it is looking to change its weather forecasting methodology in its IRP load forecast because of the version of Staff's trend analysis for weather normalization that the Commission adopted in NPC's and SPPC's last general rate cases. (Tr. at 28-29.) NV Energy states that it has procured the services of Eric Fox to develop a new load forecast—a hybrid weather normalization that looks somewhat historically, but also looks at trends. (*Id.*) NV Energy states that it plans to introduce this new weather forecasting methodology in its 2021 IRP. (*Id.*)

NV Energy states that it also develops near-term load forecasts for operational planning and resource optimization to: (1) commit and schedule generating units; (2) develop gas burn forecasts, (3) procure market purchases for meeting native load requirements, including demand, operating reserves, and ancillary services; and (4) portfolio optimization. (*Id.* at 8.) NV Energy provides that it develops near-term forecasts for two different horizons: day-ahead and real-time. (*Id.*) NV Energy states that it develops the day-ahead forecast each business day concurrent with day-ahead wholesale market trading, while it develops the real-time forecast throughout each day, based upon market and system operating conditions. (*Id.*) NV Energy adds that any differences between the near-term forecast and the actual loads are largely driven by temperature but, because the near-term forecast is developed closer to the actual period, the weather forecast is more accurate. (*Id.*) NV Energy states that the average hourly difference from the actual hourly difference for the week of August 17, 2020, is approximately 230 MW in the day-ahead forecast and 170 MW in the real-time forecast for the combined system. (*Id.*at 9.)

NV Energy states that in early July 2020 it experienced an equipment failure on the Higgins Generating Station Unit 2 ("Unit 2"), which resulted in a forced outage on the unit and a loss of 225 MW. (*Id.* at 6.) However, NV Energy states that since this forced outage was known, it did not plan to have generation from Unit 2 available during the week of August 17, 2020. (*Id.*) NV Energy states that during the week of August 17, 2020, all anticipated internal generation materialized for NV Energy's use. (*Id.*)

NV Energy states that, following the failure in July, its internal staff completed an investigation and root cause analysis ("RCA"). (*Id.*) NV Energy provides that the preliminary root cause of the generator failure appears to be fatigue failure of the bolt that attaches the bus bar to pole flex link. (*Id.*) NV Energy adds that following the RCA performed by its internal staff, Power Systems, Mfg. ("PSM"), the NV Energy's Long-Term Service Agreement ("LTSA") contractor, completed disassembly and performed another RCA. NV Energy states that the RCA report provided by PSM was a preliminary report, with the final report expected in the first quarter of 2021. (*Id*.) Additionally, NV Energy states that it performed an inspection and maintenance of the other Higgins's exciter during the plant outage, including replacement of diodes and bolting, and cleaning of the exciter. (*Id.*) NV Energy states that it developed a Generation Standard to provide guidance for future maintenance and inspection of the other exciters in NV Energy's generating fleet. (NV Energy's December 23, 2020, Comments at 12.) NV Energy states that similar brushless exciters are located at the Silverhawk Generating Station, which NV Energy plans to have inspected during a planned outage in January of 2021. (*Id*.)

NV Energy states that due to variability of renewable resources and the hotter than normal weather resulting from climate change, it is assessing both the long-term and short-term planning reserve margins. (Tr. at 30-31.) NV Energy states that it has retained the services of E3 to do a detailed assessment of the appropriate long-term planning reserve margin. (*Id.*) NV Energy states that it is planning to file an amended ESP Update for summer 2020 with the Commission to address the short-term planning reserve margin. (*Id.*)

NV Energy states that no modifications to its existing policies and procedures are necessary and that it is not necessary at this time to open a rulemaking addressing the Commission's ESP regulations because the Commission can deviate from the regulations, as necessary. (Tr. at 130; NV Energy's December 23, 2020, Comments at 7.) NV Energy states that the mechanisms currently in place allow for sufficient flexibility to address unexpected or unanticipated events. (NV Energy's December 23, 2020, Comments at 7.) NV Energy states, however, that the Commission could revisit this in a future rulemaking. (Tr. at 130.)

NV Energy states that it follows its Energy Risk Management and Control Policy (see Appendix 2C in Nevada Power DEAA Docket No. 20-02026), which the Risk Committee manages and approves. (NV Energy's December 23, 2020, Comments at 7.) NV Energy states that it applies this policy to all physical and financial transactions related to energy procurement, energy sales, and energy hedging in accordance with ESPs or IRPs approved by the Commission. (*Id.* at 7-8.) NV Energy provides that the President and Risk Committee must approve any variances from the approved ESPs or IRPs. (*Id*.)

NV Energy states that the Risk Committee meets on a regular basis, typically monthly, but holds special sessions as needed. (*Id.* at 8.) NV Energy provides that as part of the monthly review an ESP Update is presented to the Risk Committee. (*Id.*) NV Energy further provides that topics for discussion include physical gas procurement, power procurement, summer peak hour capacity positions, and coal procurement. (*Id.*) NV Energy states that based on current data at the time of each presentation, recommendations are made to continue with the current procurement levels or to modify the procurement levels based on items such as changes in market conditions or the loss of generation capacity. (*Id.*) NV Energy states that this process provides flexibility to make modifications between the four-season laddering strategy Request for Proposal ("RFP"). (*Id*.)

Nevada Gold Mines' Comments

Nevada Gold Mines states that it ran its Western 102 and TS power plants at full capacity during the week of August 17, 2020, to help provide capacity to NV Energy. (Tr. at 14.)

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BCP's Comments

BCP states that NV Energy's load forecasts during the week of August 17, 2020, seem to be within a reasonable margin of error considering day-ahead normal weather forecasting errors that NV Energy receives from its weather forecasting. (BCP's November 24, 2020, Reply Comments at 2.) BCP adds that NV Energy should be able to undertake week-ahead forecasts using near-term forecasted weather to determine if NV Energy is entering a critical supply period. (*Id.* at 3.) BCP points out that there were no noted major supply issues for NV Energy's generating stations or long-term supply contracts during the week of August 17, 2020, and it appears that the main reason for the reliability issues were due to curtailments to both firm and non-firm wholesale market purchases of up to 1,000 MW. (*Id.* at 2.)

BCP states that barring the curtailment of NV Energy's wholesale market purchases, NV Energy had adequate supplies to meet its resource requirements. (*Id.*at 2.) BCP notes that potential natural gas failures on the Kern River or TransCanada pipelines could significantly affect NV Energy's generating resources and impact NV Energy's resource adequacy. (*Id.* at 3.) BCP states that NV Energy states that a catastrophic failure of the Kern River natural gas pipeline requires approximately 72 hours to repair and may take longer in more rugged terrain based upon the terrain and time of year. (BCP's November 24, 2020, Reply Comments, Attachment DR BCP 1-02.) However, BCP states that NV Energy notes in its response that, due to two parallel lines that are connected with crossover pipe and multiple supply flow options, the likelihood of a Kern River incident that would significantly impact gas deliveries into the Las Vegas Valley is unlikely. (*Id.*) BCP states that potential natural gas failures should be further evaluated to ensure adequate mitigation measures are established in the event of an unlikely failure of natural gas supply to NV Energy. (BCP's November 24, 2020, Reply Comments at 3.)

Staff's Comments

Staff states that the actual summer 2020 peak load was 1,861 MW for SPPC and 5,965 MW for NPC. (Staff's November 24, 2020, Reply Comments at 2.) Staff states that the forecasted summer 2020 peak load from NV Energy's 2018 IRP was 1,739 MW for SPPC, 6.6 percent lower than the SPPC's actual peak load, and was 5,589 MW for NPC, 6.3 percent lower than NPC's actual peak load. (*Id.* at 1.) Staff notes that the forecasted summer 2020 peak load from NV Energy's 2019 ESP Update was 1,872 MW for SPPC, 0.6 percent higher than actual, and 5,813 MW for NPC, 2.5 percent lower than actual. (*Id.* at 2.)

Staff states that based on Exhibits 2 and 3 to NV Energy's October 5, 2020, Comments, NV Energy's worst day-ahead forecast was within 9 percent of the actual forecast and that in most hours during the week of August 17, 2020, the percentage difference between day-ahead forecast and the actual forecast was much smaller. (*Id.*). Staff notes that the Las Vegas Valley temperatures during the week of August 17, 2020, were approximately 10 degrees Fahrenheit higher than normal. (*Id.*) Staff states that it did not see any issues with NV Energy's load forecasting that would have contributed to reliability during the week of August 17, 2020. (*Id.*.) Staff states that it is aware that NV Energy is looking into the way it normalizes loads given future climate change concerns and believes that any changes to methodologies related to load forecasting, such as weather normalization, should occur in the context of a full IRP. (*Id.*)

Staff states that since NV Energy closed its open capacity position for summer 2020 at the end Quarter 1 2020, the current ESP procurement process is essentially done at the end of

March in any year and any issues that arise between March and the end of the summer are remedied using short-term purchases. (Id. at 2-3.) Staff states that the reliability events during the week of August 17, 2020, demonstrate that there may be a need for an interim process (between the end of March and a given point during the summer, such as early July) to reevaluate the open capacity condition. (*Id.* at 3.)

Staff states that one-half of the Higgins Generating Station was placed into a forced outage at the beginning of July 2020, causing NV Energy to lose approximately 225 MW and to enter the hottest summer months with a 225 MW shortfall, which was equivalent to lowering the planning reserve margin from 13 percent to approximately 9.8 percent. (*Id.* at 3). Staff states that NV Energy's planning reserve margin is meant to cover higher temperatures and economic growth than forecasted and short-term outages of generation or transmission capacity; not to cover a long-term/multi-month loss of a generating unit for the entire summer. (*Id*.) Staff states that NV Energy could have or should have issued an additional summer capacity RFP in early July 2020 to cover the long-term loss of the 225 MW associated with the extended forced outage at the Higgins Generating Station, rather than relying on its remaining planning reserve margin to backfill the lost capacity. (*Id*.) However, Staff notes that because of issues within the wholesale market during the week of August 17, 2020, it questions whether the capacity procured through the RFP process would have been delivered on August 18, 2020. (*Id.*) Staff notes that the recent stipulation in Docket No. 20-09001, NV Energy's 2020 ESP Update, addresses some of the concerns regarding short-term outages/derates associated with solar energy resources by reflecting the lower September capacity rating for the entire summer peak period. (*Id.*)

Staff states that according to the ESP regulations, specifically Nevada Administrative Code ("NAC") 704.9504, deviation and amendment of energy supply plans should be reviewed to see if additional prescriptive guidance needs to be included regarding a mandatory interim open capacity re-evaluation. (*Id.* at 3-4.) Staff notes that the regulation already requires NV Energy to continually monitor its ESP and to deviate from the plan should circumstances warrant, including an extended outage of a generation unit. (*Id.* a 4.) Staff states that the regulation may need more specific guidance, such as covering capacity that is lost from an extended outage at a generating unit, especially during much of the summer peak period. (*Id.* at 3-4.)

Commission Discussion and Findings

The Commission finds that energy supply planning and load forecasting are integral pieces of resource adequacy planning. First, NV Energy's long-term hourly load forecasting appears to have a high percentage of error. The Commission understands that differences between actual hourly loads and forecasted hourly loads in NV Energy's long-term load forecast exist due to forecasting a weather profile across the year that assigns weather conditions to days based upon a previous year and adjusts based upon the day of the week. However, NV Energy's actual hourly load exceeded its 4th IRP Amendment every hour during the week of August 17, 2020, and exceeded its 2019 ESP Update hourly load forecast every hour after 11:00 a.m. The hourly load forecasting errors averaging 21 percent and 34 percent during the week of August 17, 2020, in NV Energy's 2019 ESP and 4th IRP Amendment hourly load forecast, respectively, warrant further investigation, and could indicate that NV Energy's current long-term hourly load forecasting methodology may not account for extreme weather conditions caused by climate change. However, because the record only contains hourly load forecasting for the week of August 17, 2020, the record is incomplete, and the Commission cannot make a determination based on the incomplete record.

Additionally, the Commission acknowledges that NV Energy has planned to update its long-term forecast weather normalization methodology in its 2021 IRP. NV Energy's 2021 IRP filing is the appropriate proceeding to address any updates to NV Energy's long-term forecast weather normalization methodology, including NV Energy's hourly weather forecasting methodology.

Therefore, the Commission finds that further investigation into the difference between NV Energy's actual hourly loads and long-term hourly load forecast is necessary.

Second, it is not clear what processes and procedures NV Energy uses to monitor and adjust its long-term load forecasting assumptions after internal approval. The meeting minutes of NV Energy's Risk Committee meetings during calendar year 2020 are included in Docket Nos. 21-03005[62] and 21-03006[63]. The Commission reviewed the meeting minutes for the purposes of this Report to understand NV Energy's internal load forecast approval process. The information provided in NV Energy's calendar year 2020 Risk Committee meeting minutes was helpful but did not resolve the Commission's questions in the instant docket related to NV Energy's processes and procedures to monitor and adjust its long-term load forecasting assumptions after they were internally approved and how the Risk Committee addressed any discrepancies.

Therefore, the Commission finds that further investigation into NV Energy's processes and procedures to monitor and adjust its long-term load forecasting assumptions after they are internally approved and how it addresses discrepancies is necessary.

Finally, it may be necessary to update the Commission's regulations. NV Energy is filing its triennial IRP in June 2021; therefore, it is appropriate to assess whether the regulations need revision to address resource adequacy issues following NV Energy's 2021 IRP filing. In addition, the Commission acknowledges that NV Energy is assessing its planning reserve margins for long-term and short-term planning. In Docket No. 20-12029, NV Energy's Additional ESP Update for 2021, the Commission accepted a stipulation that increased NV Energy's planning reserve margin ("PRM") to 18 percent for 2021 and required NV Energy to update its PRM in its ESP for the 2022-2024 period to be filed on or before June 1, 2021. NV Energy's ESP for the 2022-2024 period is the appropriate proceeding to evaluate NV Energy's PRM.

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[62] Application of Nevada Power Company d/b/a NV Energy for approval of fuel and purchased power expenses, to reset the Temporary Renewable Energy Development charge, reset all components of the Renewable Energy Program Rate, reset the Base Energy Efficiency Program Rates, reset the Base Energy Efficiency Implementation Rates, reset the Energy Efficiency Program Amortization Rate, reset the Energy Efficiency Implementation Amortization Rate, and refund the total amount of Base Energy Efficiency Implementation Rate revenue received in 2020, including carrying charges.

[63] Application of Sierra Pacific Power Company d/b/a NV Energy for approval of fuel and purchased power expenses, to reset the Temporary Renewable Energy Development charge, reset all components of the Renewable Energy Program Rate, reset the Base Energy Efficiency Program Rates, reset the Base Energy Efficiency Implementation Rates, reset the Energy Efficiency Program Amortization Rate, and reset the Energy Efficiency Implementation Amortization Rate.

Therefore, the Commission finds that it may be necessary to update the Commission's regulations following NV Energy's 2021 IRP filing. The Commission is unable to make this determination until after the final order in NV Energy's 2021-2024 Joint IRP has been issued.

B. Balancing Authority Transmission System Operations and Related Issues

Introduction

As discussed above in the Overview, Section II. A., NV Energy is the BAA that covers the majority of Nevada. In that role, NV Energy ensures the reliability of the transmission system within the state. NITS customers, who are provided transmission service pursuant to NV Energy's Open Access Transmission Tariff ("OATT"), are those entities that use the transmission system, which are not bundled retail customers of NV Energy.

A list of NV Energy's current NITS customers is attached as Attachment A. Some NITS Customers take DOS from NV Energy. The Commission approved the transition of these customers to DOS pursuant to NRS 704B in Docket Nos. 04-2006, 06-07026, 08-03025, 15-05006, 15-05017, 16-09023, 16-11034, 16-11035, 17-05014, 18-09015, and 18-12019. DOS customers are all new NITS customers that were changed from bundled retail customers to NITS customers for planning purposes within the past 10 years. NV Energy is responsible within the BAA for the reliable operation of the transmission system to serve these customers pursuant to FERC and NERC rule. What is less clear for the purposes of this Report is where NV Energy's NITS customers exist in NV Energy's load-planning responsibilities.

Background on DOS Service

The regulatory framework regarding DOS customers is currently in a state of flux. Senate Bill 547 ("SB547"), passed during the 2019 Nevada Legislative Session, over-hauled the process and ability for customers of NV Energy to procure their energy, capacity, and ancillary services from a "provider of new electric resources." The Commission is currently establishing regulations related to SB547 in Docket No. 19-06029.[64]

The current regulations in NAC Chapter 704B provide the Commission very limited oversight of the providers (which Docket No. 19-06029 is addressing). NAC Chapter 704B also does not address resource adequacy for DOS customers or their providers. However, pursuant to NAC 704B.370(1), the NRS 704B customers were obligated to provide the Commission with the following information:

> 1. Except as otherwise provided in this section, not later than 40 calendar days after the date on which the eligible customer files an application, the eligible customer shall file with the Commission the following agreements:(a) A completed and fully executed distribution service agreement between the eligible customer and the electric utility. The distribution service agreement must include, without limitation: (1) A list of each point of delivery at which the eligible customer intends to purchase energy from the provider and, for each such point of delivery: (I) The physical location of the point of delivery; and (II) The current account number for the point of delivery, the name on each such account and the current billing address and final billing address for each such account; and (2) A

[64] Rulemaking to amend, adopt, and/or repeal regulations in accordance with Senate Bill 547 (2019).

detailed plan for the avoidance of involuntary curtailments of energy or capacity to the remaining retail customers of the electric utility in the event that: (I) The eligible customer is unable to secure supply for 100 percent of its load; (II) The eligible customer is no longer being served by operating reserves; and (III) The electric utility in good faith determines that it is unable to provide replacement resources to the eligible customer without negatively impacting system reliability. (3) The detailed plan may include provisions for standby service, load shedding, recourse to reliably available market resources and any other measures or combination of measures reasonably designed to avoid involuntary load curtailments by the electric utility. (b) A completed and fully executed transmission service agreement and operating agreement with the electric utility meeting all requirements of its OATT.

For the purposes of background in this Report, below is an illustrative discussion of the requirements of NV Energy for planning to serve the load of DOS customers following a transition to DOS. This includes the timing of the review and approval by the Commission of the plan pursuant to NAC 704B.370(1), by which the DOS customer purchases ancillary services from NV Energy and establishes conditions for load shedding. The illustrative discussion utilizes Docket No. 15-05017, as the customer/applicant in that case also participated in the workshop in this docket.[65]

The Applicant in Docket No. 15-05017 filed an Application with the Commission on May 12, 2015. On page 4 of the Application, the applicant stated:

> Provider will provide energy, capacity and ancillary services to meet the load requirements of MGM's facilities from electric resources located outside the service area of Nevada Power. Upon exiting, MGM has no intention of taking service for the NRS 704B accounts listed in Exhibit B from Nevada Power generating facilities or receiving energy from generation assets that are contractually committed to Nevada Power.

The Application indicated the applicant's intent to negotiate and file with the Commission the multiple other agreements and plans required pursuant to NAC 704B.370(1), as was customary.[66] On October 5, 2015, Staff filed testimony of Adam Danise in Docket No. 15-05017. Recommendation II of that testimony stated:

> Find that the proposed departure of the MGM's 59 accounts will not negatively impact the reliability of NPC's transmission system nor will it negatively impact the reliability of NPC's electrical service to remaining customers[67]

The discussion following that recommendation was solely focused on NV Energy's transmission system. Subsequent to this, Mr. Danise conditioned his recommendations on "MGM complies with all directives and other requirements ordered by the Commission."[68] Those compliances were to include the agreements and plans pursuant to NAC 704B.370(1).

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[65] NO CONCLUSIONS should be drawn from the choice of this particular docket for this purpose, as it was a well-pled and litigated exemplar of an NRS 704B Application before this Commission.
[66] Docket No. 15-05017, Application dated May 12, 2015, at pages 5-7.
[67] Docket No. 15-05017, Danise testimony filed October 1, 2015, at 19 of 26, l. 24.
[68] Danise testimony at page 23 of 26, l. 17.

NV Energy provided testimony, but it did not discuss any of NV Energy's responsibilities pursuant to the Open Access Transmission Tariff ("OATT").

On November 16, 2015, the parties to Docket No. 15-05017 filed briefs. The applicant argued in its Closing Legal Brief at page 9, as follows:

> Therefore, MGM urges the Commission to find that its agreement to pay an impact fee and to refrain from purchasing energy directly from Nevada Power and Sierra is not contrary to the public interest. Alternatively, Tenaska has agreed that it would employ reasonable efforts to put into place internal protocols to ensure that its traders are instructed to determine that the initial source in a transaction is not a Nevada Power or a Sierra resource.[69]

The Commission issued an Order on January 20, 2016, approving the applicant's request. In that Order, the Commission acknowledged that "MGM states that Tenaska can 'prevent directly contracting with Nevada Power to use energy supplied by Nevada Power as part of the supplies Tenaska would deliver to MGM ….'"[70] The Commission included a compliance to be filed within 120 days in its Order for the agreements and plans pursuant to NAC 704B.370(1). (Ordering Paragraphs 7 and 8).[71]

On May 19, 2016, the Applicant made a compliance filing in satisfaction of the Commission's Modified Final Order, which the Commission later found to be acceptable. In that compliance filing, the applicant included:

> The MGM and Nevada Power have negotiated and entered into a NITS Agreement and a Network Operating Agreement ("NOA") with the accompanying Transmission Reduction Plan ("TRP") (collectively, the "Transmission Agreements"). The Transmission Agreements which are attached to [Docket No. 15-05017] as Attachments B, C, and D, respectively.
>
> The NITS agreement within Attachment B contains specific customer load and meter infrastructure data, which MGM requests the Commission and parties in this docket maintain as confidential. The TRP also contains similar specific MGM customer load and meter infrastructure data, as well as a negotiated plan to address the unlikely but possible need for load reductions or curtailment, which MGM also requests the Commission and Parties maintain as confidential.[72]

Given the confidential claim as to the Transmission Reduction Plan, it cannot be cited here. The Commission accepted the compliance filing. Consistent with these agreements, one year after the applicant filed its Application with the Commission, the applicant informed the Commission of its intent to obtain ancillary services from NV Energy. Although the agreements are largely confidential, the terms of NV Energy's ancillary services offerings are not.

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[69] Docket No. 15-05017, Closing Legal Brief of MGM Resorts International, filed on November 16, 2015, at 9, l. 10-15.

[70] Docket No. 15-05017, Modified Final Order issued January 20, 2016, at page 5, paragraph 7.

[71] *Id* at page 80 and 81.

[72] Docket No. 15-05017, Compliance Filing of MGM Resorts International on May 19, 2016, on page 6, l. 1-11.

All NV Energy NITS customers are served pursuant to NV Energy's OATT. The OATT is a FERC-jurisdictional tariff.[73] The Ancillary Services (Schedules 4, 5 and 6) are attached as Attachment B. If a NITS Customer purchases these ancillary services from NV Energy, NV Energy is obligated to provide a one-hour reserve to cover loss of the customer's source of supply. Further, if NV Energy does not have sufficient reserves available, NV Energy is obligated to acquire reserves and directly charge the NITS customer.

NV Energy's DOS customers have elected to purchase ancillary services from NV Energy. The purchase of ancillary services under the OATT appears to create an obligation for NV Energy's transmission unit to plan for and to procure resources to serve the NITS (and DOS) customers' loads, to some extent. In Docket No. 15-05017, until the May 16, 2016, Compliance Filing wherein the applicant elected to purchase ancillary services from NV Energy, the record includes nothing to indicate that NV Energy would need to plan for MGM's load. Nonetheless, most NV Energy DOS customers rely on NV Energy pursuant to the OATT when their resources are not delivered.

Participant Comment

NV Energy's Comments

NV Energy states that it is a BA within the WECC. (NV Energy's November 11, 2020, Comments at 1.) NV Energy states that the WECC is currently conducting an August 2020 Heatwave Event Analysis to supplement the CAISO's investigation regarding the reliability events of August 2020. (*Id*. at 1-2.) NV Energy states that WECC's analysis focuses on the period of August 14, 2020, through August 19, 2020, and it is scheduled to complete its final report in early December. (*Id*. at 2). However, during the December 16, 2020, Workshop, NV Energy stated that the WECC scheduled its final report to be issued in the first Quarter of 2021. (Tr. at 55-56). NV Energy states that WECC's Preliminary August 2020 Heatwave Event Analysis suggested near-record demand levels in California during the analysis period. (NV Energy November 11, 2020, Comments at 2.)

NV Energy states that the WECC's summer peak of 161,350 MW occurred on August 18, 2020, at hour ending ("HE") 15. (*Id*.). Regarding WECC's preliminary report, NV Energy states that on August 17, 2020, six BAs within the WECC region were in an EEA event above EEA0. (*Id*.) On August 18, 2020, six BAs were in an EEA event above EEA0, including three of the six BAs that experienced an EEA event above an EEA0 on August 17, 2020. (*Id*.) On August 19, 2020, two BAs experienced an EEA event above an EEA0, one of which was in an EEA event above EEA0 on the previous two days. (*Id*.)

NV Energy states that WECC's review shows that seven BAs made a public appeal to reduce electricity and five BAs implemented firm load shedding of 100 MW or more under emergency operation policy during the week of August 17, 2020. (*Id*.) NV Energy states that it communicated public appeals to conserve energy but did not need to implement firm load shedding during the week of August 17, 2020. (*Id*.) NV Energy states that the preliminary results from the WECC's August 2020 Heatwave Event Analysis did not provide any summary of detail surrounding transmission constraints or outages of other transmission providers in the WECC region. (*Id*. at 3.) In response to Commission questions during the December 16, 2020,

[73] NV Energy's OATT can be found at the following link: OATT_Published_032321Effective052219.pdf (oati.com)

Workshop regarding NV Energy's implementation of the specific recommendations contained in the WECC's preliminary report, NV Energy stated that it was reviewing the report and did not have any information available at that time. (Tr. at 55-56 and 114-115.)

NV Energy states that there were two tie lines experiencing outages on August 17, 2020, one in the north – the Gonder-Intermountain Power Project ("Gonder-IPP") intertie with Los Angeles Department of Water and Power – and one in the south – the Red Butte intertie with PacifiCorp. (NV Energy's October 21, 2020, Comments at 6.) NV Energy states that the Gonder-IPP intertie was back in-service at HE 9 on August 18, 2020, and there were no scheduled activities on the intertie until August 19, 2020 (*Id.*) NV Energy further states that the Red Butte intertie was back in-service by HE10 on August 18, 2020, with scheduled activity resuming soon after. (*Id.*) NV Energy states that neither outage negatively impacted its ability to respond to any event or maintain system reliability during the week of August 17, 2020. (*Id.*; NV Energy's November 6, 2020, Comments at 3.)

NV Energy states that it did not restrict any energy exports from its BAA during the week of August 17, 2020, because they were associated with contracts with firm transmission tags. (NV Energy's December 23, 2020, Comments at 8.) NV Energy states that the North American Energy Standards Board governs transmission service transactions and has a curtailment priority based upon the requested service. (*Id.*) NV Energy states that export curtailments of non-firm transmission tags are permitted during non-zero EEA events, however, during the week of August 17, 2020, when NV Energy was in a non-zero EEA event, there were no non-firm transmission tags to curtail. (*Id.*) Additionally, NV Energy states that under its OATT, the transmission provider may only curtail firm transmission service (exports or imports) if curtailment is required to maintain reliable operation on its transmission system. (*Id.*) NV Energy states that these exports are associated with firm contracts that have the second highest curtailment priority just below native load customers. (*Id.*) NV Energy states that exports cannot be curtailed for utilization on system generation not owned by NV Energy and that these exports are not associated with CAISO transactions. (*Id.*)

GBT's Comments

GBT states that although there may have been excess supply available in parts of the WECC, that excess could not be imported into the CAISO due to reduction of imports. (GBT's November 24, 2020, Reply Comments at 2.) GBT states that a major path into CAISO, the Pacific AC Intertie, was de-rated due to weather, which exacerbated the CAISO's tight market conditions. (*Id.*) GBT states that the WECC's analysis of the August heatwave events found transmission outages caused limitations on north to south energy transfers within the WECC. (*Id.*) GBT states that for solar-heavy BAAs, like CAISO and Nevada, it is prudent to look at other diverse renewable resources that can serve the evening peak demand and new transmission options that can help increase import capability into the BAAs. (*Id.*) GBT states that if NV Energy had access to diverse wind resources, such as resources from Idaho, through a new transmission path, such as the Southwest Intertie Project North ("SWIP-N"), it would have more access to firm energy and likely would have avoided the market conditions it witnessed. (*Id.*)

GBT states that as Nevada continues to add more in-state solar generation, including the more than 3,000 MW of photovoltaic solar in the queue expected to be in-service by the end of 2024 in NPC alone, the issue of serving evening peak demand will become even more important. (*Id.* at 2-3.) GBT recommends that NV Energy incorporate these findings into its IRP in Docket

No. 20-07023 and analyze benefits of increasing import capability and adding diverse renewable energy resources into its supply mix to maintain reliable, continuous service. (*Id*. at 3.)

Shell's Comments

Shell states that August 2020 was unseasonably hot throughout the entire Western Interconnection. (Shell's December 14, 2020, Comments at 1.) Shell states that this resulted in higher load, ultimately stressing the grid as less surplus energy was available to move between regions to meet system peak conditions. (*Id*.) Shell states that unplanned transmission outages and interchange schedule curtailments disrupted the normal flow of energy during critical periods, which caused BAAs across the Southwest and the CAISO to shed load due to inadequate supply to meet demand. (*Id*.) Shell states that NV Energy relied on up to 1400 MW of exports from the CAISO to meet its native load due to lack of local supplies, as hot weather and transmission outages reduced supply available for imports from the Pacific Northwest. (*Id*.)

Shell states that reliability failures experienced in the CAISO and surrounding BAAs during August 2020 illustrate the interconnected nature of the bulk electric system ("BES"). (*Id*. at 2). Shell adds that constraints, outages, and curtailments in one region of the Western Interconnection forced many BAAs to shed load to protect the BES. (*Id*.) Shell states that each BAA in the Western Interconnection sets standards and targets for reliable operation, under NERC and WECC reliability standards. (*Id*.) Shell states that most of these BAAs are situated in regions of the WECC which are bilateral, with purchases and sales made directly between counterparties. (*Id*.) Only one BAA, the CAISO, is outside of this bilateral construct. (*Id*.) Shell states that until FERC Order 831 is fully implemented in the CAISO markets, there is misalignment in price caps in the CAISO markets and bilateral regions of WECC which undermine reliability. (*Id*.) Shell states that as prices increased outside the CAISO due to supply scarcity, the CAISO exported power to Nevada and other regions and, as a result, exports sourced from the CAISO's BAA were curtailed so native load in the CAISO would not be interrupted. (*Id*.) Shell states that this action was unprecedented; curtailments of firm exports had a destabilization effect in other BAAs, and BAAs subsequently curtailed native load as they lost firm interchange schedules due to curtailments (*Id*.)

Shell states that there are very few conditions which allow firm interchange transactions to be curtailed under WECC and NERC reliability standards. (*Id*.) Shell states that the CAISO is currently examining its export interchange scheduling priorities and processes in its market and its imperative for the CAISO and other BAAs to work together to harmonize any approach consistent with WECC and NERC reliability standards. (*Id*. at 2-3.) Shell states that it had contracts for firm and non-firm transmission service to serve its load obligations in Nevada that were not met with exports from the CAISO and thus not affected by the CAISO's export curtailments. (*Id*. at 3.) Shell states that due to an unplanned transmission outage on transmission service contracted by Shell, firm transmission capacity was curtailed due to the outage and its load obligations were significantly affected by these curtailments. (*Id*.) Shell adds that it was successful in resupplying its obligations by arranging alternative transmission service. (*Id*.)

MGM and Caesar's Comments

MGM and Caesars state that there is definitely a need to coordinate with other BAAs. (Tr. at 141-142.) However, MGM and Caesars state that because export curtailment between

BAAs is not jurisdictional to the Commission, the Commission does not have easy access to information. (*Id.*) MGM and Caesars state that NPC may be able to help the Commission obtain relevant information. (*Id.*)

Staff's Comments

Staff states that it would like NV Energy to explain if it curtailed or limited exports out of NV Energy's BAA to California or any other area during the week of August 17, 2020, and, if not, to explain why it did not curtail or limit exports. (Staff's November 24, 2020, Reply Comments at 8.)

Commission Discussion and Findings

The Commission has several concerns regarding BA transmission system operations and related issues. Although the Commission's jurisdiction is not all-encompassing, pursuant to NRS 704.001, it still must ensure safe and reliable electric service in Nevada, and this Report approaches these issues from that vantage point. First, the Commission is concerned that participants do not have a clear expectation or understanding, pursuant to NV Energy's OATT, of what happens to DOS customers during events like what occurred the week of August 17, 2020. Second, the Commission is concerned with the lack of coordination between NV Energy and other BAAs. Therefore, the Commission finds that NV Energy's coordination with other BAAs within the WECC to address curtailment of imports and exports between BAAs and to ensure BAAs are not all relying on the same imports to maintain resource adequacy may help avoid curtailments and boost efficient transacting.

As Staff noted in its November 24, 2020, comments in this docket, the energy resources for multiple DOS customers, as well as several other NITS customers, were not delivered in several hours in August 2020.[74] Staff's comments express concern that these unbundled retail transmission customers leaned on the generation that NV Energy had procured for NV Energy's retail customers.

At the workshop held on December 16, 2020, the Commission questioned MGM and Caesars about this concern. Below is the relevant portion of MGM and Caesars's response to the Commission questions:

> This one incident, that only lasted for a few hours, has generated a lot of interest, obviously, but I don't think the system failed in terms of the way it's set up at the FERC level.
>
> And both my customers also, like Wynn, have Transmission Reduction Plans and, you know, should we have been responsible for not doing something we need to, in other words, as has been implied, leaning on the system and not supplying or scheduling appropriate load, they have the right to call my clients and ask them and require them to reduce load or cut off load at certain – in a certain order, which is in our confidential Transmission Plan.

[74] Staff November 24, 2020, Comments at 4.

> We were not asked to do that, and I think that's because we did not do anything, and our provider didn't do anything, inappropriately in terms of planning for our power loads.
>
> And the other thing I would respond to in terms of earlier comments that were made, both my clients were asked to cut back, to cut back service during these periods, and both of them made significant efforts to do so and did reduce load.[75]

Tenaska filed Comments on December 11, 2020, also asserting that the system had functioned as expected the week of August 17, 2020. Tenaska further explained that NV Energy was required to plan for the loads of its NITS customers:

> Thus, FERC requires a Transmission Provider to engage in system planning to ensure it is acquiring sufficient Operating Reserves to meet the expected loads of its NITS customers, including the 704B Customers, and to meet their expected need to rely on these Operating Reserves. This means that a Transmission Provider must project expected loads of 704B Customers and anticipate contingencies that might occasion the need for deployment of the Transmission Provider's Reserves.
>
> These Operating Reserve Services (in conjunction with the Energy Imbalance Service discussed below) are, from a 704B Customer's perspective as a Network Customer of [NV Energy], analogous to [NV Energy]'s retail Large Standby Service Rider, which some retail customers pay [NV Energy] to ensure electric service in the event of an interruption of their supply arrangements. The Operating Reserves entitle the 704B Customer to rely on [NV Energy] as a source of backup energy supply in the event that the 704B Customer's scheduled resource is curtailed or otherwise unavailable. Therefore, 704B Customers are already paying [NV Energy] for back-up service pursuant to [NV Energy]'s FERC-approved OATT, and [NV Energy] has the obligation to have sufficient Operating Reserves to serve all these customers or to acquire enough reserves if [NV Energy] does not already have them.[76]

Tenaska's explanation and the language in the OATT plainly describe that NV Energy has some responsibility to plan to serve its NITS customers' loads. However, serving a large commercial customer pursuant to a retail tariff and serving a large commercial customer pursuant to the DOS tariff and the OATT are not the same. After reviewing the information submitted in this docket, it is apparent that the Commission records that were created in prior cases regarding NRS 704B applications may have been incomplete.

During the workshop on December 16, 2020, many questions were raised about the implementation of Schedules 4, 5, and 6 of the OATT, and no one present had a definitive explanation regarding the intent of the OATT. Staff stated that its opinion is that "[it does] not believe [the intent] is to cover 50 or 100 percent of a departed customer's load for three, four hours in duration, because that's not ancillary reserve service, that's full service."[77] MGM and

[75] Tr. at 77, l. 21 to 78, l.16
[76] Tenaska Comments filed On December 11, 2020 at 4.
[77] Tr. at 42, l 12-16.

Caesars questioned the proper role of the Commission in terms of planning for the loads of NV Energy, stating:

> And these network customers or loads that rely upon the utility, they're substantially more than 704B customers, is my first point, and we've never planned for the other part in the actual planning of the resource plan. When I look at a loads and resources table, none of these other entities are added in there, and I don't think it's fair to actually single out or focus solely on the 704B. Probably it's being done because, you know, they changed service providers within the last couple of years.
>
> But the system has functioned effectively, you know, without the PUC seeking and getting information from all these other customer over time. It's the function of the Transmission Division of the Company to plan for that, and to do so through its FERC – through FERC oversight and jurisdiction. And in saying that, I also want to point out that this incident that occurred this last August didn't really result in anybody, as you noted at the beginning of the workshop, in anyone losing load. And I think that's important to note, because under the current loads and resources that the Company plans for, they're relying on well over a thousand megawatts of market power themselves through the transmission service, so substantially more load than any group of 704B customers would have.[78]

There are many unanswered questions about the proper application of Schedules 4, 5, and 6. Prior Commission proceedings have not provided the Commission with adequate information regarding NV Energy's responsibilities under federal and state law. Although the OATT is a FERC-jurisdictional tariff, this Commission requires a clear record of how NV Energy intends to interpret and apply its NITS obligations and load-shedding related to ensuring resource adequacy in Nevada.

There is an open rulemaking, Docket No. 19-06029, where the Commission is establishing rules surrounding requirements for licensing providers of new electric resources and further exits from bundled service. The participants in Docket No. 19-06029 have negotiated draft regulation language for all three phases, and the Commission has submitted this language to the Legislative Counsel Bureau ("LCB"); however, LCB has only returned the second phase regulations. At present, the Commission has not adopted any phases of the regulations in Docket No. 19-06029. This allows the Commission an opportunity to address resource adequacy related to DOS customers and providers of new electric resources in that docket and in the regulations governing the NRS Chapter 704B process. The Commission directs that many of the unanswered questions from the workshop in this docket about the proper application of OATT Schedules 4, 5, and 6, to the extent they are not addressed in another proceeding, shall be properly addressed in Docket No. 19-06029.

Further, the Commission is concerned about the apparent lack of coordination and communication within the WECC region between the BAAs regarding resources and resource adequacy. Further work must be done in coordination and communication, and the WECC's recent reports regarding resource adequacy provide a starting point. Therefore, the Commission

[78] Tr. at 38 l. 1 to 39, l. 6.

finds that NV Energy's coordination with other BAAs within the WECC is necessary to avoid curtailments and boost efficient transacting. The issues for discussion and coordination include addressing the curtailment of imports and exports between BAAs and ensuring BAAs are not all relying on the same imports.

C. Wholesale Market Consideration for Planning

Introduction

The CAISO operates competitive day-ahead and real-time wholesale energy markets and an EIM market.[79] The CAISO's day-ahead market opens bidding seven days before and closes the day prior to the trading date and consists of three separate market processes that run sequentially.[80] First, a market power mitigation test is performed. (*Id.*) Second, the integrated forward market ("IFM") clears energy and virtual supply bids against both virtual demand and demand bids to set energy prices. (*Id.*) Finally, the residual unit commitment ("RUC") process clears the energy supply against the CAISO's demand forecast and creates generating resource commitments, which are announced in the afternoon the day ahead. (*Id.*) The CAISO's real-time market opens bidding after 1:00 p.m. prior to the trading day and closes 75 minutes before the start of the trading hour and dispatches generating resources for each 15-minute and 5-minute interval of the trading hour. (*Id.)*

The CAISO's EIM is an extension of CAISO's five- and fifteen-minute real-time market to Balancing Authority Areas outside of the purchase and sale of incremental energy to balancing supply and demand. (CAISO FERC OATT, Section 29 at 2). The CAISO's EIM dispatches economic bids voluntarily offered by participating entities that have excess resources to efficiently balance supply, transfers between BAAs, and load across its footprint through excess transmission capacity that is donated to the EIM. (CAISO Business Practice Manual for Energy Imbalance Market, Version 21 at 12).

During August 2020, the CAISO experienced unprecedented peak demands due to a west-wide extreme heat wave that caused demand to exceed its electricity resource adequacy and planning targets. (CAISO/California Public Utilities Commission ("CPUC")/California Energy Commission ("CEC") January 12, 2021, Final Root Cause Analysis ("Final Root Cause Analysis") at 1.) As a result, the CAISO enacted an EEA3 and instituted rotating electricity outages in California on August 14 and 15, 2020. (*Id.*) The CAISO, the CPUC, and the CEC were required to report to the California Governor on the root causes of the event leading to the August outages, and further details of the CAISO, CPUC, and CEC investigations and actions are outlined below. (*Id.*)

CAISO – Root Cause Analyses, Department of Market Monitoring Report, Tariffs, and Results

Root Cause Analyses

The CAISO, CPUC, and CEC produced a Preliminary Root Cause Analysis on October 6, 2020, and its Final Root Cause Analysis on January 12, 2021. The analyses concluded in

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[79] http://www.caiso.com/market/Pages/MarketProcesses.aspx, https://www.westerneim.com/pages/default.aspx
[80] http://www.caiso.com/market/Pages/MarketProcesses.aspx

these two reports that the three major causal factors contributing to the August 2020 California outages were as follows:

1. The climate-changed extreme heat wave across the United States resulted in demand for electricity exceeding existing electricity resource adequacy and planning targets.

2. In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.

3. Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

(Final Root Cause Analysis at 1.)

The Final Root Cause Analysis summarized the market practices in the day-ahead energy market that exacerbated the supply challenges faced by the CAISO. (*Id.* at 5.) In particular, after the CAISO's rolling electricity outages on August 14-15, 2020, the CAISO determined that its energy market practices contributed to its inability to obtain additional energy that could have alleviated the strained conditions on its system. (*Id.* at 61.) The contributing causes identified by the CAISO included: that the following practices that obscured the tight physical supply conditions included: (1) under-scheduling of demand in the day-ahead market by load serving entities or their scheduling coordinators; (2) convergence bidding, which is a form of financial energy trading used to converge day-ahead and real-time pricing; and (3) a market enhancement combined with real-time scheduling priority rules, which caused the CAISO's day-ahead RUC process to fail to detect and respond to the obscuring effects of under-scheduling and convergence bidding. (*Id.* at 5.)

The Final Root Cause Analysis states that the CAISO was developing solutions to these market design issues but noted that most of the day-ahead supply challenges were addressed in the real-time market as a result of additional cleared market imports, energy imbalance market transfers, and other emergency purchases. (*Id.* at 5.) Additional information on each of these market practices that exacerbated the CAISO's supply problems is provided below.

Under-scheduling of demand. Scheduling coordinators representing LSEs in California collectively under-scheduled their demand and energy by 2,164 MW and 2,023 MW below the actual peak demand for August 14 and 15. (*Id.* at 61.) During the net peak demand time,[81] the under-scheduling was 1,272 MW and 1,547 MW for August 14 and 15. (*Id.*) According to the Final Root Cause Analysis, under-scheduled load by these scheduling coordinators limited the ability of the day-ahead market to secure sufficient supply to meet actual demand. (*Id.*) Consequently, more exports were scheduled in the day-ahead market than were supportable from internal resources. (*Id.*) To understand the cause of the under-scheduling, the CAISO surveyed scheduling coordinators, who reported the following challenges with accuracy: data quality and availability, extreme weather conditions, COVID-19 and shelter-in-place impacts, and changes

[81] "Net peak demand" is the peak of demand net of solar and wind generation resources. Final Root Cause Analysis at 4.

in the entities serving load within California. (*Id.* at 62.)

Convergence Bidding Masking Tight Supply Conditions. Convergence bids are non-physical positions taken in the day-ahead market and liquidated in real-time for converging prices between the day-ahead and real-time markets that would otherwise not be achievable with only physical bids. (*Id.*) According to the CAISO, under normal conditions, when there is sufficient supply, convergence bidding plays an important role in aligning resources for the next day. (*Id.*)

On August 14 and 15, the under-scheduling of load and the fact that the bulk of the convergence bids clearing the day-ahead market were financial supply positions and not demand positions created the ability of the day-ahead market to clear more exports than were physically supportable. Given this, on August 16, the CAISO temporarily suspended convergence bidding for August 18 through August 21. (*Id.* at 62.)

Residual Unit Commitment Process. The RUC process is part of the CAISO's day-ahead market and, according to the CAISO, provides reliability checks based on the CAISO's forecast of CAISO load after it has cleared the IFM. (*Id.* at 63.) The IFM is based on schedules and bids for supply and demand. (*Id.*) After reviewing the performance of the day-ahead market for August 14, the CAISO determined a market enhancement that was made to the RUC process was masking the effects of load under-scheduling and convergence bidding. The market enhancement, in fact, erroneously signaled that more exports were physically supportable than actually were. (*Id.*)

The CAISO modified the RUC process on September 5, 2020. (*Id.*) According to the Final Root Cause Analysis, the modification ensures that exports that are not physically feasible in the day ahead are appropriately reduced in the RUC process. (*Id.*) The CAISO also modified the real-time market input priorities so that only those exports found to be physically feasible in RUC are given a high priority in the real-time market rather than those cleared in the IFM. (*Id.*)

The Final Root Cause Analysis notes that while the RUC process was problematic, the CAISO's real-time market and operations helped significantly reduce the combined effects of load under-scheduling and convergence bidding in the RUC process. (*Id.*) In particular and relevant to the EIM, the Final Root Cause Analysis states that the CAISO was able to rely on real-time market and operations to attract more imports, including market transactions, voluntary transfers from the EIM, and emergency transfers from other balancing authorities. (*Id.*)

Department of Market Monitoring Report

The CAISO also identified issues of concern in its Department of Market Monitoring ("DMM") Report issued on November 24, 2020, regarding system and market conditions, issues, and performance for August and September 2020 ("CAISO DMM Report").[82] One concern was with regard to the volumes, prices, and self-scheduling of exports. (*Id.* at 46.)

Specifically, prior to August 14 and 15, 2020, the CAISO market participants offered increasing volumes of exports in the day-ahead market at very high prices or as self-schedules. (*Id.*) Export self-schedules are demand bids for a specified energy amount without a price,

[82] Many of the findings from the CAISO DMM Market Report were incorporated into the Final Root Cause Analysis. Final Root Cause Analysis at 8.

indicating that the bidder will purchase energy at any cost. (*Id.*) Market participants submitting export self-schedules that specify the export is backed by non-resource adequacy capacity receive a "price taker" scheduling priority, while export self-schedules that do not identify it as backed by non-resource adequacy capacity receive a "less than price taker" scheduling priority. (*Id.*) A "price taker" has a higher scheduling priority than a "less than price taker" scheduling priority. (*Id.*)

Regarding these exports, the CAISO DMM Report found that while the amounts of exports clearing the day-ahead IFM were increasing, these self-scheduled exports were not backed by imports being wheeled through the CAISO or contracts with capacity within the CASIO. (*Id.*) Additionally, as discussed in the Final Root Cause Analysis, self-scheduled exports cleared the RUC process even though they were not supported by physical supply. (Final Root Cause Analysis at 63.) More specifically, the RUC process allowed day-ahead, self-scheduled exports from the IFM that did not submit revised economic bids in real time to receive the highest real-time scheduling priority, regardless of whether it was backed by non-RA capacity (price-taker or less-than-price-taker exports). (CAISO DMM Report at 52.)

In fact, during the rotating electricity outages in California on August 14, 2020, the CAISO exported approximately 3,000 MW of hour-ahead scheduled exports that received a real-time scheduling priority above that of the CAISO's native load.[83] (*Id.* at 8.) While the export situation was a concern, the CAISO stated that it did not know whether reducing exports would have prevented the rotating electricity outages. (Final Root Cause Analysis at 64.)

The CAISO DMM Report also revealed how much the CAISO relied upon the EIM during the critical periods in August. (CAISO DMM Report at 3.) Specifically, the DMM Report found that the CAISO was the largest net importer in the EIM during the most critical ramping hours of the summer 2020 heat wave. (*Id.*) During curtailment intervals on August 14-15, the EIM provided an average of 1,346 MW and 530 MW, respectively, into the CAISO system. (*Id.*) The DMM Report found that most of the transfers were from adjacent balancing areas in the southwest, including NV Energy's balancing area. (*Id.* at 40.) The DMM Report concluded that these transfers offset a significant portion of the additional CAISO area demand that was created by exports to these balancing areas through the day-ahead market.[84] (CAISO DMM Report at 7, 40.)

The CAISO DMM Report also conducted additional analysis on the EIM transfers and congestion during August 14 and 15. (CAISO DMM Report at 40.) The analysis showed that the CAISO was the only major importer in the EIM during hours ending 19 and 20 on August 14, with NV Energy and Portland Gas & Electric also importing relatively small quantities. (*Id.*) The CAISO also was the largest net importer in the EIM during these same hours on August 15. (*Id.*) The DMM Report notes that EIM transfers are a function of both regional supply conditions and transfer limitations. (CAISO DMM Report at 40-42.) To examine those conditions, the CAISO examined export and import constraints on hours ending 19 and 20 on August 14 and 15. (*Id.*) Most of the export constraints affected balancing authorities in the northwest given transmission constraints. (*Id.*) NV Energy, however, was import-constrained

[83] The CAISO did curtail a limited amount of export energy on August 14 and 15. CAISO DMM Report at 6.
[84] On August 14 and 15, approximately 2,900 MW of exports were scheduled out of the day-ahead market on interties connecting the CAISO with adjacent balancing areas in the southwest, including NV Energy's balancing area. CAISO DMM Market Report at 6.

relative to the greater CAISO/EIM system on August 14 and 15 because it failed the upward sufficiency test. (*Id.*) The DMM Report states that the constraint limited the availability of energy outside of NV Energy to serve its load during that time period. (*Id.*)

Actions Taken after CAISO's Rotating Outages that Affected Nevada and the EIM

As noted above, after the CAISO's rolling electricity outages on August 14-15, 2020, the CAISO determined that its energy market practices contributed to its inability to obtain additional energy that could have alleviated the strained conditions on its system. (Final Root Cause Analysis at 61.) Going into August 17-18, 2020, the CAISO's day-ahead load forecast projected even higher loads than the CAISO experienced days earlier when the CAISO was required to institute rotating outages; these projections would potentially surpass the CAISO's 1-in-10-year peak demand load forecast. (CAISO DMM Report at 11.) Also, for August 17-18, the CAISO's day-ahead resource adequacy bids were not sufficient to meet the CAISO's forecasted load plus ancillary service requirements and self-scheduled exports. (CAISO DMM Report at 8 and 22.)

To address this situation, on the evening of August 16, 2020, the CAISO announced the suspension of its day-ahead virtual bidding for the August 18, 2020, operating day and informed scheduling coordinators with scheduled day-ahead exports for August 17, 2020, that those export schedules could be curtailed if conditions warranted. (CAISO DMM Report at 8.) According to the DMM Report, the suspension was designed to prevent virtual supply bids from allowing additional exports from being scheduled in the day-ahead market, which would ultimately need to be met by physical supply from within the CAISO system. (*Id.*) At that time, RUC was not identifying exports with IFM schedules that could not be supported by physical supply capacity. (*Id.*) The effect of suspending virtual bidding on August 18 was to limit exports entering the real-time market and to give priority to the CAISO's native load. (*Id.* at 48.) And, in fact, the CAISO curtailed exports on August 18.[85] (*Id.* at 8.)

The DMM Report describes CAISO's current policy as prioritizing exports that receive RUC awards over native CAISO balancing area load in real-time. (CAISO DMM Report at 5.) While the DMM Report states that curtailment of exports should be avoided when possible, given the detrimental impacts that export curtailment can have on other balancing areas,[86] the

[85] However, on August 17 to 19, load within the CAISO system was not curtailed. CAISO DMM Report at 8.

[86] The CAISO/CPUC/CEC Preliminary Root Cause Analysis described the potential detrimental impacts of curtail exports as follows:

> [T]here are significant operational matters that need careful consideration before curtailing cleared and tagged exports in real-time. In order for such curtailments to be even be implemented effectively, information about the individual exports and relative priorities would have to be readily available to the operators. Furthermore, those relying on such exports need to be made aware of the potential risk of such exports being curtailed in advance so that they can take measures to avoid being put into an emergency condition upon loss of such exports. Absent such operator information or neighboring BAAs being aware of curtailments in a timely manner, curtailing cleared and tagged exports during quickly emergent real-time conditions would not be consistent with coordinated and good utility practices. Furthermore, the curtailment of the export may not be effective in addressing the reliability issue. In other cases, cutting the exports may further exacerbate conditions as curtailment of an export may result in the cutting of an import at the applicable intertie because the interchange was permissible only due to counterflow provided by the export. Finally, when the CAISO is in the position of relying on emergency energy from its neighbors, the threat of an export curtailment to another BAAs when conditions are constrained throughout the system may prevent access to emergency energy either at that time or in the future.

DMM Report states that additional changes and clarifications were needed to the RUC rules and other market processes to address exports in the future. (*Id.*) As such, the DMM Report recommends further changes and clarifications in the rules and processes for limiting or curtailing exports, with the goal being to establish equal treatment and expectations for exports by all neighboring balancing areas. (*Id.*) at 4-5.) The DMM Report states that the CAISO and WECC balancing areas' ultimate policy on the priority of exports relative to native load will be a critical factor in CPUC resource adequacy reforms and the CAISO market design initiatives, including for the extended day-ahead market. (*Id.* at 5.)

The CAISO reinstated virtual bidding in the day-ahead market on August 22 even though the CAISO had not yet fixed the underlying RUC export and real-time scheduling processing issue. (CAISO DMM Report at 8.) By August 22, market conditions had changed so that virtual bidding was again viewed as providing market benefits without presenting a risk to system reliability. (*Id.*)

On September 5, 2020, CAISO adjusted the RUC process to ensure that the exports not backed by capacity contracts cleared in the IFM would not receive RUC scheduling priority if there was not sufficient physical supply in the RUC process to support them. (*Id.*at 53.) As a result of these changes, exports that clear the IFM, but are reduced in the RUC process, no longer receive a real-time scheduling priority. (*Id.*) To reinstate the priority scheduling of the export, the exports must be re-bid in real time or resubmitted as self-schedules in real time, and then the export will still receive a scheduling priority below the supply of electricity in real-time for CAISO native load. (*Id.*)

For the longer term, the CAISO, CPUC, and CEC stated the intention to work with other regional stakeholders to establish a modernized, integrated approach to forecasting, resource planning, and resource adequacy targets. (Final Root Cause Analysis at 3.) According to the Final Root Cause Analysis, this enhanced collaboration and alignment are meant to more fully anticipate events like last summer's climate-change-induced extreme heat wave and better plan and account for the transitioning electricity resource mix necessary to meet clean energy goals. (*Id.*) Part of this effort will examine statewide and WECC-wide resource sufficiency. (*Id.*) In particular, the Final Root Cause Analysis states that the CEC, in coordination with the CPUC, CAISO, and other BAAs, will begin developing a statewide summer assessment to provide additional information to support resource adequacy processes to maintain situational awareness of the WECC-wide summer assessments and publish information as appropriate. (*Id.* at 73.)

CAISO Mar. 26, 2021, Amendment Filed at FERC to Implement Summer 2021 Market Enhancements

On March 26, 2021, the CAISO submitted its first set of tariff amendments to prepare for the Summer of 2021. (CAISO, Tariff Amendment, Docket No. ER21-1536-000, filed with the FERC on Mar. 26, 2021 ("CAISO Mar. 26 Tariff Amendment"))[87]. The CAISO proposed five categories of tariff revisions: (1) incentives for import schedules in the Hour Ahead Scheduling Process ("HASP") during tight market conditions; (2) reliability demand response resource dispatch and real-time price impacts; (3) EIM coordination and resource sufficiency test; (4) pricing enhancements during tight system conditions; and (5) generation interconnection

Initial Root Cause Analysis at 106-07.

[87] The CAISO Mar. 26 Tariff Amendments were approved by the FERC in an Order issued on May 25, 2021.

process improvements. (CAISO Mar. 26 Tarff Amendment at 3.) The CAISO requests that the FERC implement the tariff changes by May 25, 20201, to be effective no later than Jun 15, 2021. (*Id.* at 2.) This Report will address the tariff amendments most relevant to Nevada.

Incentives for HASP. The first change is to provide bid cost make-whole payments for hourly intertie block schedules issued through HASP that provide energy during tight system conditions. (*Id.* at 3, 13-22.) The make-whole payment provisions will apply only in those hours for which the CAISO has issued a notice of an anticipated or actual operating reserve shortage. (*Id.*) The proposed tariff revisions seek to incentivize incremental imports during these narrowly defined operating conditions. (*Id.*) The CAISO's current import settlement rules may not sufficiently incentivize suppliers to offer hourly block economic imports to the CAISO in the real-time market because, although the real-time market clears hourly block import bids based on HASP prices, it settles them at fifteen-minute market prices. (*Id.*)

Proposals to improve EIM operations and coordination. The CAISO made two proposals aimed at improving EIM operations and coordination. (*Id.* at 3, 27-32.) First, the CAISO proposes to add to the capacity test component of the EIM resource sufficiency evaluation an uncertainty requirement that captures a BAA's net load variability. (*Id.* at 3.) This modification will require participating EIM BAAs to submit sufficient schedules and bids to account for their net load forecast uncertainty, in addition to sufficient schedules to cover their forecasted load. (*Id.* at 4.) The CAISO's proposal arises from its review of findings in the root cause analysis and discussions with stakeholders regarding the resource sufficiency evaluation's performance during last summer's tight conditions. (*Id.*) By requiring BAAs provide sufficient capacity to meet their uncertainty needs in addition to forecasted load, the CAISO's proposal will better ensure each BAA brings sufficient resources into the real-time market. (*Id.*)

The second EIM-related change mandates each EIM BAA use an automated market feature that updates the EIM BAA's "mirror resource" schedule when the market awards an import at a CAISO intertie scheduling point sourced from the EIM BAA. (*Id.*) A mirror resource is one or more resources the EIM BAA has designated as the source of imports at CAISO scheduling points. (*Id.*) These imports are separate from EIM transfers resulting from the EIM's resource-specific dispatch. (*Id.*) This enhancement results from the CAISO's review of operational issues that occurred during last summer's heat event during which the CAISO's market systems and an EIM BAA used incorrect information in connection with updating a mirror resource's schedule. (*Id.*) As a result, the market optimization relied on incorrect information about supply resources available to the EIM for dispatch. (*Id.*)

The CAISO states that it has committed to commencing a stakeholder process later in 2021 to undertake a more comprehensive examination of potential changes to the resource sufficiency evaluation and consider changes to the consequences of failing the tests. (*Id.*) The CAISO notes that two stakeholders suggested the CAISO defer making any EIM-related changes pending the outcome of this comprehensive stakeholder process. (*Id.*)

CAISO Apr. 28 Tariff Amendment Filed at FERC to Implement Market Enhancements for Summer 2021 for Load, Export, and Wheeling Priorities

On April 28, 2021, the CAISO submitted a tariff amendment to implement market enhancements for the summer of 2021. (CAISO, Tariff Amendment, Docket No. ER21-1790-000, filed with the FERC on Apr. 28, 2021 ("CAISO Apr. 28 Tariff Amendment")). The CAISO states that the proposed tariff revisions arise from the root cause analyses of the load shed event in August 2020, as well as from the CAISO discussion with stakeholders in the Market Enhancement for Summer 2021 Readiness stakeholder initiative. (*Id.*at 1). The CAISO states that the proposed tariff revisions are critical to ensure that, during constrained conditions, the CAISO can manage transactions at the interties and internal transmission paths reliably and fairly to meet its native load obligations and provide access to external entities that rely on the CAISO grid to serve load. (*Id.* at 1-2).

The CAISO states that to address the risks it faces in 2021, some of the proposed tariff revisions must become effective in July. (*Id.* at 2.) The CAISO submitted three sets of tariff revisions with different effective dates. (*Id.*) The first set consists of a new defined term, Priority Wheeling Through, and an eligibility notification provision, to become effective on June 28, 2021. (*Id.*) The second set contains the other load, export, and wheeling through related tariff revisions, which are to become effective no later than July 15, 2021. (*Id.*) Because the CAISO intends all wheeling through tariff revisions to be interim only, the CAISO is submitting a third set of tariff revisions that remove the new wheeling through provisions from the CAISO tariff effective June 1, 2022. (*Id.*)

*Tariff modification to scheduling priorities for self-scheduled exports***.** The CAISO proposed two changes to these scheduling priorities. (CAISO Apr. 28 Tariff Amendment at 4, 32-33.) First, low-priority recallable exports that are awarded day-ahead market schedules will have a lower priority than the CAISO load in the real-time market. (*Id.* at 4.) Low-priority recallable exports are defined by the CAISO's tariff as "self-schedules of exports not explicitly sourced by non-Resource Adequacy Capacity." (*Id.* at 4 n.9.)[88] The second proposed change in scheduling priorities is that low-priority recallable exports deemed feasible in the RUC process and self-scheduled into the real-time market will receive a priority higher than the new low-priority recallable exports bidding into the real-time market. (*Id.* at 33.) According to the CAISO, under today's rules, low-priority recallable exports scheduled in the day-ahead market have a higher priority than the CAISO load in the real-time market. *Id.* at 4.) This creates the possibility that the market will use resource adequacy capacity intended to serve the CAISO internal load to support exports. (*Id.*) The proposed changes also ensure that exporters procuring resources to serve their load in the day-ahead market have a higher priority than those that do not. (*Id.* at 4-5.) The change encourages forward scheduling of low-priority recallable exports, which should allow the CAISO to set schedules that are more reliable in the day-ahead. (*Id.* at 5.)

Tariff amendments regarding capacity supporting high-priority, non-recallable exports. The CAISO proposed several new rules and requirements regarding the capacity that can support high-priority, non-recallable exports, which are: capacity supporting a high-priority, non-recallable export must be forward contracted only with an external LSE; capacity supporting high-priority, non-recallable exports must be available and physically capable of sustaining the high-priority, non-recallable export quantity for the entire hourly block; capacity supporting a high-priority, non-recallable export must be deliverable; only resources internal to the CAISO can support a high-priority, non-recallable export, distinguishing such exports from wheeling through transactions; if a supporting resource does not receive a schedule in the IFM equal or greater than the corresponding high-priority, non-recallable export, the supporting resource must

[88] By contrast, high-priority non-recallable exports are defined as "self-schedules of exports at Scheduling Points explicitly sourced by non-Resource Adequacy Capacity." CAISO Apr. 28 Tariff Amendment at 4 n.10.

submit a $0/MW RUC availability bid up to the export self-scheduled quantity; and resources must submit real-time market bids for the quantity of high-priority, non-recallable export they are backing in order for the export to be high-priority. (*Id.* at 5, 34-46.)

The CAISO states that these rules will better ensure that capacity supporting high-priority, non-recallable exports (1) is not otherwise contracted with a CAISO LSE; and (2) is available and physically capable of meeting its schedule so capacity procured to serve CAISO native load does not support the export. (*Id.* at 5-6.)

Tariff revisions to facilitate allocation of de-rated capacity. Today, the CAISO only knows whether the capacity of a de-rated resource is resource adequacy or non-resource adequacy. (CAISO Apr. 28 Tariff Amendment at 6, 47-49.) Scheduling coordinators do not advise the CAISO whether non-resource adequacy capacity is unsold capacity, capacity sold to a CAISO LSE but not shown on a monthly resource adequacy plan, or capacity sold to an external LSE for export. (*Id.* at 6.) Thus, the CAISO does not know exactly how it should allocate any de-rated capacity among the various categories of a unit's capacity or the extent to which a de-rated resource can support a high-priority, non-recallable export. (*Id.*) To address this situation, the CAISO proposes to require scheduling coordinators requesting planned outages or notifying the CAISO of forced outages that partially derate a resource to advise the CAISO of the extent the outage affects resource adequacy capacity and any contracted non-resource adequacy capacity. (*Id.*)

Tariff amendments affect wheeling through schedule priorities. Regarding this proposed tariff change, the CAISO proposes that on an interim basis, through May 31, 2022, to establish two categories of wheeling through, self-schedule transactions as follows: a Priority Wheeling Through and a non-Priority Wheeling Through. (*Id.* at 6-7, 49-62.) The existing CAISO tariff does not specify the scheduling priorities for wheeling through transactions, except in limited circumstances. (*Id.* at 7.) Priority Wheeling Through transactions will have a priority equal to CAISO load and high-priority, non-recallable exports in the day-ahead and real-time market optimization processes. (*Id.*) The CAISO proposes to define a Priority Wheeling Through transaction as wheeling through self-schedule supported by (1) a firm power supply contract to serve an external LSE's load for the entire calendar month; and (2) month firm transmission form the source to the CAISO border for hours ending 07:00 through 22:00, Monday through Saturday excluding NERC holidays. All other wheeling through self-schedules are non-Priority Wheeling Through transactions. The scheduling coordinator for Priority Wheeling Through transactions must notify the CAISO that it meets the eligibility requirements 45 days before the month. (*Id.* at 8.) Non-Priority Wheeling Through transactions will have a lower priority. (*Id.* at 7.)

Priority Wheeling Through transactions can be curtailed pursuant to CAISO's proposal. (*Id.* at 7.) The CAISO states that a market adjustment process is necessary to adjust import schedules and wheeling through transactions to apportion transmission capacity fairly when the system is constrained, and the CAISO is at risk of not serving its load. (*Id.*) Specifically, when an Intertie is constrained in the import direction by a scheduling limit or Path 26 is constrained in the north-south direction, and the HASP cannot meet CAISO's forecast of demand or fully accommodate a Priority Wheeling Through transaction, the CAISO proposes to perform a process after HASP to allocate available transmission capacity pro rata between supply needed to meet CAISO load and Priority Wheeling Through transactions. (*Id.*)

The CAISO acknowledges that this particular proposal was contentious, and stakeholders were deeply divided. (*Id.* at 9.) The CAISO stated that many stakeholders oppose the wheeling through priority proposal in whole or in part. (*Id.*) The CAISO also acknowledged that some stakeholders argue that this proposal violates open access principles, although the CAISO argues it does not do so. (*Id.*) NV Energy filed comments on CAISO's proposed market enhancements for Summer 2021 readiness on February 3, 2021, asking several questions as to the fairness of the CAISO's proposals.[89] Given the contentious nature of this proposal and the fact that it came out of an expedited stakeholder process, the CAISO has proposed to sunset the wheeling through tariff revision on May 31, 2022, and work with stakeholders on a more "durable solution." (*Id.* at 9.)

Participant Comments

NV Energy's Comments

Wholesale market conditions for NV Energy during the week of August 17, 2020

NV Energy states that, as part of the ESP, it implemented a four-season laddering strategy in the first quarter of 2020 to purchase wholesale market energy to close its open summer peak capacity positions for that year. (NV Energy's October 5, 2020, Comments at 3.) NV Energy explains that it makes three types of market purchases: (1) term; (2) day ahead; and (3) real time. (*Id.*) NV Energy makes term purchases in advance from 24 to 3 months. (NV Energy October 21, 2020, Comments at 4.) Day-ahead purchases and real-time purchases are executed based on near-term forecasts. (*Id.*)

NV Energy states that term purchases are the power market transactions executed in compliance with the laddering strategy approved in the ESP. (*Id.*.) NV Energy further states that short-term procurement activities, such as day-ahead and real-time trading, bridge the gap between long-term energy supply planning and actual energy supply needs. (NV Energy's October 5, 2020, Comments at 3.) NV Energy provides that real-time trading involves the procurement of power purchase resources for delivery within the same day of the transaction execution. (*Id.*) NV Energy states that it relies on these power market transactions to ensure a continuous balance of energy supply and demand due to variations in system conditions (loads and resources). (*Id.*)

NV Energy states that purchase volumes for these short-term transactions are at the highest levels during the summer months, which corresponds with NV Energy's annual peak demand for energy supply. (*Id.*) It is common for NV Energy to transact at volumes in excess of 1,000 MW for a given hour in the summer. (*Id.* at 3-4.)

NV Energy states that most day-ahead and real-time purchases are for firm energy; firm energy places a commitment on the seller to ensure deliverability. (NV Energy October 21, 2020, Comments at 4.) When firm market products are not feasible to purchase due to available supplies, NV Energy will procure non-firm resources. (*Id.*) NV Energy states that while firm purchases are generally more reliable, all market purchases (firm and non-firm) are subject to curtailments. (*Id.* at 5.)

[89] *See* https://stakeholdercenter.caiso.com/Comments/AllComments/BBC85FDD-01B0-4901-B544-81791BA65481#org-0973b72e-4680-474c-8c7d-661dd96a48f7

On Monday, August 17, 2020, and Tuesday, August 18, 2020, NV Energy performed standard day-ahead trading activities. (NV Energy October 5, 2020, Comments at 4.) However, on those days, NV Energy states that the market was severely restrictive with heavy buyers and few sellers. (*Id.*) NV Energy states that routine suppliers were unable or unwilling to transact with NV Energy. (*Id.*) During the day-ahead trading process at the CAISO, feedback from counterparties suggested an overall concern about market uncertainty. (*Id.*)

NV Energy states that it exhausted all available supply options standard through day-ahead activities, as well as extended trading activity beyond day-ahead market timelines; it expanded trading efforts to include additional market products such as unit-continent energy; and it submitted bids for additional supply through the CAISO day-ahead market awards. (*Id.*)

NV Energy states that day-ahead trading was unable to locate sufficient energy resources for closing the day-ahead position. (*Id.*) NV Energy states that given its inability to secure sufficient resources, notifications began on Monday, August 17, 2020, informing senior leadership and support staff of the potential for an EEA should market constraints continue. (*Id.*)

On Tuesday, August 18, 2020, and Wednesday, August 19, 2020, variances occurred between the day-ahead planning forecasts and actual operating conditions. (*Id.* at 5.) For example, some energy supply procured in advance was no longer deliverable by counterparties due to curtailments. (*Id.*) Also, while real-time native load demand increased to near record highs, market constraints in the real-time market continued. (*Id.*)

As another example of the market constraints, NV Energy reported that bilateral trading experienced reductions in liquidity during the week of August 17, 2020, with up to four trading counterparties indicating they were not offering any power for sale and expressing an overall concern about market uncertainty surrounding the CAISO market and potential for supply curtailments. (NV Energy November 6, 2020, Comments at 4.) There were three counterparties that executed bilateral transactions with NV Energy for Tuesday and Wednesday, August 18 and 19, 2020, but those counterparties were only willing to sell non-firm power. (*Id.*) Real-time liquidity for such contracts was equally as constrained, with routine counterparties indicating that they were not able to show offers for energy. (*Id.*)

The result was that NV Energy could not procure the required amount of energy from the wholesale market to maintain system resource adequacy due to the market conditions. (*Id.* at 5.) NV Energy stated that the illiquidity of the wholesale energy market during the summer of 2020 was the highest it had ever experienced – usually NV Energy is able to procure any energy needs in the wholesale energy market. (Tr. at 122.)

Specific to NV Energy, given the illiquidity of the market during the week of August 17, 2020, there were more than 100 hours with market purchases ranging between 25 MW to 550 MW per hour that were non-firm (unit or transmission contingent). (NV Energy October 21, 2020, Comments at 4.) NV Energy states that this level of non-firm purchases was not typical. (*Id.*) In that week, NV Energy also said curtailments affected market availability of energy. (*Id.*) There were 76 hours of firm and non-firm purchases that were curtailed, meaning that actual delivered energy was less than the confirmed term, day-ahead, and real-time purchases. (*Id.*) Nine of the 76 hours had curtailments greater than 500 MW, and seven of those hours occurred on August 18, 2020. (*Id.* at 4-5.) On average, there were 11 hours each day of the week of August 17, 2020, where the procured term, day-ahead, and real-time purchases were curtailed.

(NV Energy November 5, Comments at 5.) The largest curtailment occurred at hour ending 19 on August 18, 2020, with a curtailment of 1,243 MW. NV Energy states it has never experienced a curtailment of this size. (*Id.* at 5.) During the week of August 17, 2020, NV Energy received feedback from counterparties that indicated that supply curtailments occurred upstream from NV Energy's counterparties and, thus, resulted in supply curtailments to NV Energy. (NV Energy October 21, 2020, Comments at 5.)

NV Energy explained that its firm energy was curtailed for a variety of reasons, some of those being related to CAISO's activities. (Tr. at 105.) Other reasons for curtailment include transmission availabilities from the Pacific Northwest and unit contingent issues. (*Id.*) Specific to the contingency issues, NV Energy stated that it did purchase unit-contingent and transmission-contingent power, and those purchases were curtailed in the day-ahead and real-time when those events occurred. (*Id.*)

Even with the significant market constraints and curtailments, NV Energy states that there were only four hours during the week of August 17, 2020, that NV Energy had insufficient internal operating reserves that resulted in reliance on the Northwest Power Pool, and no customer experienced an outage during the period of the shortfall. (NV Energy Nov. 6 Comments at 5.)

According to NV Energy, if firm purchases had been delivered and its transmission customers avoided leaning on its system, the shortfall of operating reserves could have been avoided. (NV Energy October 21, 2020, Comments at 8-9; NV Energy November 6, 2020, Comments at 8-9.) Specifically, for all hours except one, which was hour ending 16:00 on August 18, 2020, NV Energy would have had sufficient operating reserves during the week of August 17, 2020. (*Id.*)

EIM participation by NV Energy generally and during the week of August 17, 2020

NV Energy states that it participated in the EIM by bidding its generating units into the fifteen- and five-minute markets during the week of August 17, 2020. (NV Energy's November 6, 2020, Comments at 7.)

NV Energy states that given that the EIM is an imbalance market, NV Energy must have sufficient resources to serve its own load and pass all EIM tests to avoid leaning on the market. (*Id.*) NV Energy also explained how flexible ramp tests in the EIM affected its resource adequacy during the week of August 17, 2020. (*Id.*) NV Energy explained that the EIM uses flexible ramp tests to determine whether each entity is well positioned to ramp generators up or down in real time as the load forecast or renewable resources move up or down without negatively impacting neighboring entities. (*Id.*) In general, NV Energy explained that a failed up test means that CAISO calculations indicate that NV Energy's generators and imported resources do not have the ability to increase output within its bid range quickly enough to meet potential increases in forecasted load or decreases in renewable resources. (*Id.*) The bid range is the minimum and maximum values within each unit can operate. (*Id.*) The CAISO uses the minimum and maximum range for each unit to calculate whether the unit has the capacity to account for variability in the load and resources table. (*Id.*) When an up flex test is failed, all EIM imports are frozen to their previous values for a 15-minute period. (*Id.*) While the market will not permit additional real-time dynamic EIM imports for this 15-minute test period, all EIM imports that were previously scheduled will continue to be honored. (*Id.*)

While NV Energy did experience failed EIM ramp tests during the week of August 17, 2020, NV Energy states that the test failures were at times that exclusion of real-time dynamic EIM imports did not affect NV Energy's ability to serve load and maintain operating reserves. (*Id.* at 8.)

In response to Commission questions as to how NV Energy acts in the CAISO market, NV Energy states that the firm purchases in the day-ahead and real-time market were not designated as network resources. (Tr. at 102.) NV Energy also stated that the point of receipt for a majority of these market purchases was Mead. (*Id.*) NV Energy also states these purchases were bilateral transactions, Schedule C contracts. (*Id.*) Schedule C contracts are curtailable.[90] (Tr. at 102-03.) NV Energy states that it did not consider procuring Schedule B contracts because Schedule B contracts are not considered firm, and NV Energy prefers firm contracts to fill its open capacity. (Tr. at 103.)

The Commission asked NV Energy whether it monitors the CAISO market and the ability of NV Energy's counterparties to deliver its energy obligations pursuant to bilateral contracts subject to the CAISO market conditions prior to the delivery period. (Tr. at 104.) NV Energy states that it does not monitor the CAISO market or the ability of its counterparties who transact in the CAISO market to meet obligations under bilateral contracts. (Tr. at 104). NV Energy states that it does not have the information or data about a counterparty's activities in the day-ahead CAISO market because that data is confidential and not made available to NV Energy. (Tr. at 106-107.) In response to Commission questions, NV Energy states that the Commission may want to evaluate the risk of procuring energy traded in the CAISO market. (Tr. at 106.) NV Energy agrees that it should assess the risks of relying on firm energy contracted for through the CAISO market. (Tr. 107-08.)

NV Energy attempts or ability to procure energy outside of CAISO

NV Energy states that it issued an RFP to look for non-CAISO source energy and that RFP was not successful. (Tr. at 108.) NV Energy claims that a non-CAISO product does not exist in the market. (Tr. at 109, 129.)

In response to BCP comments, NV Energy states that a physical "week ahead" market does not exist, but there is a "Next Week" product that trades in some markets. (NV Energy's December 23, 2020, Comments at 10.) However, NV Energy states that the "Next Week" product is a financial product that is often used speculatively or to hedge potential unit issues, such as when there is uncertainty around a generating unit's return to service dates. (*Id.* at 10-11). As an example, NV Energy states that the Palo Verde "Next Week" product is financial and not liquid, as it has not transacted on the Intercontinental Exchange since November 2016. (*Id.*) NV Energy adds that a weekly product is a one-off product for any counterparty, as counterparties neither market nor plan for such a product; counterparties with large amount of excess sell their excess seasonally, while counterparties with less certain excess availability sell into the CAISO's day-ahead market. (*Id.*)

CAISO's Market Process, Resource Sufficiency, and Market Enhancements

NV Energy filed a Motion to Intervene and Protest regarding the CAISO April 28 Tariff

[90] While NV Energy stated at the workshop that Schedule C contracts are curtailable, this statement is unclear to the Commission in that Schedule C contracts are purported to be firm.

Amendment. (Motion to Intervene and Protest of NV Energy, Docket No. ER21-1790-000, filed with FERC on May 17, 2021 ("NV Energy Protest"). NV Energy states that the CAISO proposes to modify the priorities for self-scheduled wheel though transactions in a manner that is unjust, unreasonable, unduly discriminatory, and inconsistent with the FERC's long-standing open access transmission principles, as reflected in the terms and conditions of the pro forma OATT that the FERC established in Order No. 888. (*Id.* at 1.) NV Energy adds that the proposed tariff amendments go impermissibly too far in favor of the CAISO LSEs to the detriment of customers in other BAA, who require transmission through California. (*Id.* at 2.) NV Energy also states that the CAISO's proposed amendments will have a significant impact on the West just two months before the summer. (*Id.*). Also, NV Energy argues that the CAISO's proposal devalues daily, weekly, and even monthly firm transmission service procured after June 29, 2021, under the OATTs of other western transmission providers. (*Id.*) This can interfere with the ability of other BAs and LSEs, including NV Energy, to respond to unplanned outages or unexpected load demands and to meet their customers' needs in an economic and reliable manner. (*Id.*) NV Energy's protest focuses on two primary elements of the CAISO's proposal: (1) the unjust, unreasonable and discriminatory limitations placed on self-scheduled wheel through transactions imported to the CAISO on firm transmission so that only a narrow category of "Priority Wheeling Throughs" will have the highest curtailment priority and (2) the CAISO's proposed changes to import curtailment priorities so that all imports of CAISO LSEs' Resource Adequacy resources, whether on firm or non-firm transmission, would have the same curtailment priority as self-scheduled wheeling throughs imported on firm transmission. (*Id.* at 3.)

GBT's Comments

Regarding both NV Energy's and CAISO's challenges during the week of August 17, 2020, GBT notes that part of the challenges stemmed from the fact that, after solar supply went down for the day, there was not enough electricity supply available to serve net demand during peak hours. (Great Basin November 24 Comments at 2.) GBT adds that all available generation within the CAISO BAA was dispatched close to max capacity and, while there may have been excess supply available in WECC, it could not be imported into the CAISO due to a reduction in imports. (*Id.*) A major import path into CAISO, Pacific Intertie, was de-rated due to weather that exacerbated the CAISO tight market conditions. (*Id.*) WECC's Preliminary Root Cause Analysis of the mid-August Heat Storm found that transmission outages caused limitations on north to south energy transfers, which also has the highest demand. (*Id.*)

GBT states that while NV Energy was in a relatively better condition than the CAISO, there are some valuable lessons to learn from this heat wave. (*Id.*) For solar heavy BAAs like the CAISO, GBT states that it is prudent to look at diverse renewable resources that can serve the evening peak demand and to look at new transmission options that can help increase import capability into the BAAs. (*Id.*) GBT argues that if NV Energy had access to diverse wind resources through a transmission path, it would have access to more firm energy and likely would have avoided the market conditions it witnessed. (*Id.*) GBT further argues that as Nevada continues to add more solar to its system, the issues regarding serving evening peak demand will become more important. (*Id.* at 2-3.) GBT recommends that NV Energy analyze the benefits of increasing import capability and adding diverse renewable resources to its supply mix as a way to maintain reliable, continuous service. (*Id.* at 3.)

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Shell's Comments

Shell states that NV Energy relied upon up to 1,400 MW of exports from the CAISO to meet its native load due to lack of local supplies. (Shell's Comments at 1.) The curtailments of exports from the CAISO to Nevada had a significant and destabilizing impact on the NV Energy BAA. *Id.*)

Shell states that the CAISO curtailments that destabilized NV Energy's BAA did not affect Shell's load obligations. (Shell's Comments at 2-3.) Shell states it has contracts for firm and non-firm transmission service to serve its load obligations in Nevada. (*Id.* at 3.) Due to an unplanned transmission outage, Shell states that its firm transmission capacity was curtailed. (Shell's Comments at 1, 3.) Shell states that it was successful in resupplying its obligations by arranging alternative transmission service and was able to increase its customer on-site generation to help meet load obligations. (*Id*. at 3.)

Shell states that the reliability failures experienced in the CAISO and surrounding BAAs during August 2020 illustrate the interconnected nature of the BES. (*Id.* at 2.) Shell states that most of the BAAs in the West are bilateral in the sense that purchases and sales are made directly between counterparties. (*Id.*) Only the CAISO operates outside the bilateral construct. (*Id.*) Until FERC Order 831 is fully implemented in the CAISO markets, Shell states that there is misalignment in prices in the CAISO markets and the other bilateral regions of WECC that undermine reliability. (*Id.*) As prices increased outside of CAISO due to supply scarcity, power was exported from the CAISO to Nevada and other regions. (*Id.*) However, exports sourced from the CAISO's BAA were curtailed by the CAISO so that native load in the CAISO would not be interrupted. (*Id.*) Shell states that this action was unprecedented and that curtailments of firm exports have a destabilizing effect on other BAAs. (*Id.*))

Tenaska's Comments

For the week of August 17, 2020, Tenaska states it submitted balanced schedules for each of its 704B customers in Nevada in accordance with Attachment P of NV Energy's OATT. (Tenaska's Reply Comments at 6.) Tenaska states it contracted with energy supplying counterparties for the delivery of firm power at the Mead interconnect for delivery of power, which Tenaska planned to resell to its Nevada customers. (*Id.* at 7.) The counterparties committed to deliver firm LD Energy or WSPP Schedule C power to Mead. (*Id.*) Tenaska states that none of the counterparties were the CAISO and that it had no control over from whom its energy supplying counterparties obtain their energy resources to deliver firm power at Mead. (*Id.*)

Tenaska states that it experienced its largest curtailments on August 18, 2020, from the hours of 17 through 19. (Tenaska's Reply Comments at 7; Tr. at 74.) All power that was curtailed was scheduled at Mead, and its upstream suppliers were sourcing out of California. (*Id.*) Tenaska notes that its suppliers' stated reasons for failure deliver energy to Mead because counterparties had arranged to acquire power from the CAISO, and the CAISO cut its deliveries to Tenaska's suppliers. (Tenaska's Comments at 7.) Tenaska states its suppliers paid it liquidated damages for these curtailments and, in some cases, Tenaska passed on those liquidated damages to its NRS 704B customers. (*Id.*)

Tenaska argues that the curtailments it experienced as a result of the CAISO were three one-hour events in that the CAISO did not curtail exports for a three-hour period. (Tr. at 74.) Tenaska states that the CAISO conducted market-based curtailments, in that the CAISO curtailed all the tags across the board. (Tr. at 74-75.) Because of the way the CAISO conducted the curtailments, Tenaska argues that there "were three stand-alone one-hour event; not a single event." (Tr. at 75.)

Tenaska states that even though the CAISO was not experiencing an EEA 3 event, the CAISO nonetheless chose to curtail all the exports out of California. (Tr. at 84.) They did not do any pro rata curtailments and instead seemed to choose the large scheduled tags that were being exported out of California for cancellation. (*Id.*)

Wynn's Comments

Wynn states that its provider procures energy in the same manner that the rest of the Chapter 704B providers do in the open market. (Tr. at 68.) The issues that occurred in August 2020 were West-wide and affected the entire WECC. (*Id.*) Wynn notes the root of the problem was the large curtailments in California; the CAISO decision to shut off exports affected everybody in the West. (Tr. at 68, 70.) Wynn states that while the CAISO was expecting renewable energy of 7 gigawatts, the actual energy delivered was 2.5 gigawatts. (Tr. at 68.) This fact, in conjunction with reduced traditional generation that were shut down or undergoing maintenance, caused procurement problems. (*Id.*) Wynn notes that this was a "perfect storm of events that we rarely see. It wasn't specific to NV Energy, Nevada, 704B, or anybody else; it was West-wide." (Tr. at 68-69.)

BCP's Comments

BCP asks that the Commission consider whether NV Energy should minimize contracting with non-firm energy during forecasted periods of high heat or CAISO curtailments. (BCP's November 24, 2020, Comments at 2.) BCP points out that non-firm contracts may be cut at any time by the supplier with no damages. (*Id.*) BCP notes that NV Energy had over 1000 MW of non-firm energy (day-ahead and real-time) that it was scheduled to rely upon during some hours in the week of August 17, 2020. (*Id.* at 2-3.) BCP states that NV Energy should be able to undertake week-ahead forecasts, considering forecasted weather to determine if NV Energy is entering a critical supply period. (*Id.* at 3.) BCP states that it appreciates that NV Energy may not be able to secure firm resources with such short notice but believes that NV Energy should make a maximum effort to secure firm resources during these periods. (*Id.*)

Staff's Comments

Staff confirms that during the week of August 17, 2020, there were firm and non-firm purchases made in the wholesale market by NV Energy that were curtailed. (Staff's Reply Comments at 7-8.) Staff states that NV Energy determined that most of the curtailments were because the CAISO limited exports, thereby denying NV Energy access to the firm capacity from the providers with whom NV Energy contracted. (*Id.* at 8.) As a result of the curtailments, there were hours during the week of August 17, 2020, in which NV Energy had insufficient operating reserves and had to rely on the NWPP. (*Id.* at 7.)

Staff stated that a broader discussion needs to occur as to whether NV Energy should assess additional risk associated with its contracts that pass through/involve the CAISO system or whether such contracts should be considered "non-firm" given the circumstances that occurred. (*Id.* at 8.) Staff also states that a discussion is required to determine if NV Energy's planning reserve margin should increase if it is going to rely on the contracts that involve the CAISO. (*Id.*)

Staff states that it appears that the export curtailment by the CAISO was a major underlying reason for the problems experienced by NV Energy on August 18, 2020. (Tr. at 17.) Staff notes its concern about the CAISO's curtailment actions on August 18, 2020, in that the CAISO did not allow any energy to be exported out of the state, regardless of what was contracted for. (Tr. at 126.) The question, from Staff's perspective, is whether this is an anomaly or whether this situation could continually occur and, thus, utilities must plan for or around such risks. (*Id.*) Given this uncertainty for markets in the West, Staff states that NV Energy needs to really consider any generation retirements in the near-term. (Tr. at 127.)

Commission Discussion and Findings

The CAISO is a critical component of NV Energy's participation in the wholesale market. According to NV Energy, a non-CAISO market product does not exist and cannot be procured. As such, NV Energy's power procurement relies on bilateral contracts with counterparties that participate in the CAISO wholesale energy markets.

Given this interaction between NV Energy's power procurement and the CAISO, the background discussion above regarding the CAISO must be considered within the Nevada planning context that was introduced in Section III. B.

NV Energy's most recently approved IRP, which included an ESP, as well as its 2019 ESP Update, are the most recent Commission-approved ESPs addressing Summer 2020. NV Energy's supply side resources for Summer 2020 totaled 7,992 MW, 147 MW more than its total required capacity. As of April 2020, NV Energy had acquired enough supply side resources to meet its forecasted August 2020 peak demand. NV Energy then relied upon the day-ahead and real-time short-term wholesale markets as needed to meet incremental energy needs based upon actual system conditions.

NV Energy utilizes a four-season laddering strategy for procuring capacity in the wholesale market to close its summer positions. This strategy was initially implemented following EEA reliability events affecting neighboring balancing authority areas in the mid-2010s in the Western Interconnect.[91] Under the laddering strategy, NV Energy would procure 25 percent of its open capacity per quarter, updated internally by NV Energy as needed, starting with the third quarter of 2018 and ending in the first quarter of 2020.[92] Therefore, by the end of Quarter 1 2020, NV Energy would have acquired enough capacity and energy to meet its forecasted summer 2020 peak load and its 13 percent planning reserve margin (referred to as "total required capacity"). NV Energy would then continue to monitor its open capacity position, load forecast, and supply side resources and seek to execute firm short-term and forward wholesale market purchases when needed to serve native load through direct negotiations with counterparties, as well as through the competitive procurement processes.[93]

From data contained in workpaper 3 of NV Energy's October 21 comments, NV Energy

[91] Docket No. 18-06003, Volume 18, Narrative at page 176 of 361.
[92] Docket No. 18-06003, Volume 18, Figure ESP-25 at page 177 of 361.
[93] Docket No. 18-06003, Volume 18, Narrative at page 177 of 361.

shows that for HE12 through HE22 during August 17-21, 2020, NV Energy procured approximately 94,491 MWh of energy on the wholesale market through bilateral contracts with various counterparties. Of the 94,291 MWh of energy procured, approximately 48,750 MWh (51 percent) were term products, 35,946 MWh (38 percent) were day-ahead products, and 9,795 MWh (10.4 percent) were real-time products. However, approximately 8,965 MWh (9.5 percent) of NV Energy's market energy purchases were curtailed through the CAISO in August 2020 for various reasons. Of the 8,965 MWh curtailed, approximately 2,663 MWh (29.7 percent) were term products, 5,577 (62.2 percent) were day-ahead products, and 725 MWh (8.1 percent) were real-time products. Day-ahead market products were curtailed the most and significantly more than real-time products during that time period.

NV Energy stated that it experienced its largest wholesale energy market product curtailment through the CAISO at the 1800 hour (HE19) on August 18, 2020. NV Energy procured approximately 2,107 MWh of wholesale market energy to be delivered during this hour but only received approximately 864 MWh of energy, meaning 1,243 MWh (59 percent) of energy was curtailed. Of the 1,243 MWh of curtailed market energy, 682 MWh (54.9 percent) were term products and 561 MWh (45.1 percent) were day-ahead projects – ***no real-time energy products were curtailed***. The following table provides an hourly breakdown of the NV Energy's curtailed market purchases during HE12 through HE22 for each weekday during the week of August 17, 2020.

Percent of Market Purchases Curtailed During HE12 through HE22 For the Period August 17, 2020 to August 21, 2020												
		HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22
8-17	Total Market Purchases Curtailed	0%	0%	0%	0%	0%	0.1%	0.1%	30.6%	38.1%	9.4%	8.4%
	Term	0%	0%	0%	0%	0%	100%	100%	4.1%	20.5%	5.6%	7%
	Day-Ahead	0%	0%	0%	0%	0%	0%	0%	87.7%	72.7%	74.7%	93%
	Real-Time	0%	0%	0%	0%	0%	0%	0%	8.2%	6.8%	19.7%	0%
8-18	Total Market Purchases Curtailed	0%	11.6%	0.7%	26.9%	29.3%	32%	43.4%	59%	45.3%	32.8%	24.4%
	Term	0%	100%	100%	6.4%	9.8%	16.7%	40.7%	54.9%	41.1%	8.5%	3.9%
	Day-Ahead	0%	0%	0%	93.4%	90.2%	81.2%	54.9%	45.1%	58.1%	91.5%	96.1
	Real-Time	0%	0%	0%	0.2%	0%	2.1%	4.3%	0%	0.7%	0%	0%
8-19	Total Market Purchases Curtailed	2.4%	1.8%	0.6%	1.3%	8.3%	7.1%	4.7%	11.4%	4.5%	1.7%	0%
	Term	100%	100%	90%	69.2%	15.1%	18.4%	28.4%	13%	27.3%	50%	0%
	Day-Ahead	0%	0%	0%	0%	0%	0%	0%	24%	56.8%	0%	0%
	Real-Time	0%	0%	10%	30.8%	84.9%	81.6%	71.6%	63%	15.9%	50%	0%
8-20	Total Market Purchases Curtailed	3.6%	2.5%	2.2%	1.4%	1.7%	0.2%	0.2%	0%	0%	0.2%	0%
	Term	100%	100%	100%	100%	100%	100%	100%	0%	0%	0%	0%
	Day-Ahead	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Real-Time	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%

8-21	Total Market Purchases Curtailed	1.6%	1.1%	1.0%	0.6%	0.8%	0.8%	0.8%	0.8%	0.8%	1.0%	1.4%
	Term	100%	52.9%	56.3%	100%	100%	100%	100%	100%	100%	100%	100%
	Day-Ahead	0%	47.1%	43.8%	0%	0%	0%	0%	0%	0%	0%	0%
	Real-Time	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
For HE12 through HE 22 on August 17, 2020 through August 21, 2020:												
Total Market Purchases Curtailed:							9.5%					
Breakdown of the Total Market Purchases Curtailed by Type:												
Term:							29.7%					
Day-Ahead:							62.2%					
Real-Time:							8.1%					

NV Energy does not specifically monitor CAISO's day-ahead or real-time wholesale energy markets to assess whether any resource adequacy or wholesale market issues within the CAISO could affect NV Energy's resource adequacy, even though NV Energy relied upon the CAISO market to meet its forecasted summer 2020 peak demand. For example, for HE18 on August 18, 2020, NV Energy procured 2,352 MW from counterparties who participate in the CAISO's wholesale energy market to meet the real-time forecasted peak demand of 7,836 MW: approximately 30 percent of NV Energy's supply resources for HE18. Additionally, as discussed in NV Energy's December 9, 2020, Risk Committee Meeting Special Session, for June through September for the years 2017 to 2020, there was an open position on average 64 days of the four-month summer period.[94] During those 64 days, 208 hours on average required a market purchase greater than 500 MW.[95]

Given the large amounts of CAISO wholesale energy product curtailments discussed previously and the changes that the CAISO has and will continue to make to its wholesale energy markets, NV Energy must assess whether there are increased risks associated with NV Energy's reliance on the CAISO wholesale energy markets to maintain system reliability.

The Commission finds that NV Energy currently relies on the CAISO wholesale market to maintain system reliability. The Commission further finds, based upon the information gathered in this investigation, that it currently does not have sufficient information about how NV Energy engages with or operates within the CAISO.

Under NAC 704.9482, NV Energy is required to provide a regional assessment of the availability of fuel and purchased power resources in its purchased power procurement plan for the period covered by the ESP. In NV Energy's 2019 ESP Update, Docket No. 19-08034, NV Energy provided an overview of the seasonal planning reserve margins reported in WECC's 2018 Power Supply Assessment for the four WECC sub-regions to indicate the ability of each sub-region to meet their load requirements with internal generation and imports from other sub-regions. Using these planning reserve margins, the WECC developed Building Block reserve margin values as an indicator of reserve adequacy.[96] Each WECC sub-region is determined to have adequate reserve margins when the anticipated planning reserve margin exceeds the

[94] Docket No. 21-03005, Volume 8, at page 53 of 300.
[95] *Id.*
[96] Docket No. 19-08034, Volume 1, 2019 ESP Update Narrative at page 165 of 206.

Building Block reserve margin.[97] However, as explained by the WECC in its February 26, 2021, Western Assessment of Resource Adequacy – Subregional Spotlight: Northwest Power Pool – Central, if all WECC subregions experience high demand and lower resource availability at the same time, imports into the Northwest Power Pool – Central Subregion (NV Energy's WECC subregion) may not be available, as was the case during the August 2020 Heatwave Event for the WECC California-Mexico subregion.[98] Although the probability of all subregions experiencing high demand and lower availability at the same time is very low, the WECC stated that as weather patterns and the resource mix continue to change, the likelihood of extreme demand and supply events stressing resource adequacy also increases.[99]

As noted above, the CAISO, CPUC, and CEC are supposed to work closely with other regional stakeholders to establish a modernized, integrated approach to forecasting, resource planning and resource adequacy targets. Part of this effort will examine statewide and WECC-wide resource sufficiency. (Final Root Cause Analysis at 3, 73.)

Finally, the Commission has filed a Motion to Intervene to provide comments regarding the CAISO April 28, 2021, Tariff Amendment in FERC Docket No. ER21-190-000. The Commission has concerns regarding the CAISO's Market Enhancements for Summer 2021and related proposed FERC tariff revisions. The Commission requested that FERC reject the tariff provision proposed by the CAISO on the grounds that its proposal was filed too late to be implemented by the Commission and NV Energy and, thus, would be too disruptive to NV Energy's Commission-approved ESP.

D. Demand Response Opportunities

Introduction

Demand response programs have long been a staple in both NPC's and SPPC's demand-side management portfolio. Demand response is an important aspect of ensuring energy supply reliability. NV Energy has provided the anticipated available demand capacity reduction from demand response programs in the loads and resources forecasts to help analyze how demand response relates to ensuring the reliability of NV Energy's supply.

Participant Comments

NV Energy's Comments

NV Energy states that the remedial actions undertaken to maintain, reliable continuous service included reviewing and assessing opportunities to achieve additional demand response reduction through NV Energy's load management program. (NV Energy's October 5, Comments at 5.)

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[97] *Id.*

[98] WECC February 26, 2021, Western Assessment of Resource Adequacy – Subregional Spotlight: Northwest Power Pool – Central at page 11.
https://www.wecc.org/Administrative/Western%20Assessment_Northwest%20Power%20Pool-Central%20Report%2020210226.pdf.

[99] *Id.*

NV Energy indicates, in the timeline of events through Tuesday, August 18, 2020, that it pursued supply options beyond market purchases such as demand response options throughout the day on August 18, 2020. (*Id*. at Ex. 1.)

NV Energy stated at the workshop that it believes the total demand response load reduction was around 180 MW for August 18. (Tr. at 24.) NV Energy stated that on August 18, 2020, it called on demand response from all customers at the same time producing a larger load reduction. (Tr. at 25.) NV Energy also stated that the demand response program played a large role in providing reliability during the summer of 2020 and the week of August 17, 2020. (Tr. at 135.) Additionally, NV Energy stated that it is considering different options and technologies for expanding its demand response program which it would bring forward in its June 2021 IRP filing. (Tr. at 136-139.)

NV Energy states that from its perspective customers were not "demand response fatigued" during the 2020 summer season. (NV Energy's December 23, Comments at 9.) NV Energy provides that the "Customer Agreement Terms and Conditions of PowerShift Program" document advises customers of the following:

- Customers are advised that energy events occur June through September;
- Customers have control over their thermostat and can decide to participate in energy events;
- Customers can elect to override at any point during an energy event;
- The program requires that customers only participate in 50 percent of energy events;
- Customers receive participation billing credits when they participate in energy events, per Tariff Schedule OLM-AS; and
- Typically, energy events last two hours, on a couple occasions during 2020 an event was called for three hours.

(*Id.*)

NV Energy states that identifying free-riders is challenging and that it is currently in the contracting process to select a consultant to conduct a net to gross ("NTG") study for its demand-side management ("DSM") programs, which also includes free-rider calculations. (*Id.*) NV Energy states that it plans to file a draft NTG study in the 2021 IRP filing. (*Id.*) NV Energy states that by educating customers, through emails, on its website, TV commercials, outreach, and other DSM programs, the team encourages customers to participate in energy events. (*Id.*) NV Energy states that customers can participate for any portion of the two to three-hour event, and do not lose control of their thermostat. (*Id.*) NV Energy states most customers do not override the energy events, and for those that do override, they may participate for thirty minutes, one hour, or any variation of time that is appropriate for their comfort. (*Id.*)

NV Energy states that a third-party M&V contractor provides specific participation results annually. (*Id.* at 10. NV Energy states that its annual M&V analysis for the 2020 residential demand response season, including participation results, will be provided with its

Demand Side section of the IRP and will include an analysis of the August events for its demand response thermostat programs. (*Id.*)

NV Energy states that, for comparative purposes, in 2018 there were 43 demand response events called for residential customers at NPC, 13 of the events (30 percent) were in August. (*Id.*) NV Energy further states that in 2019, for the same group, there were 39 demand response events called, 15 of the events (38 percent) were in August. (*Id.*) Finally, NV Energy states that in 2020, that same group experienced 50 demand response events, 19 of the events (38 percent) were in August. (*Id.*)

In response to the Commission's workshop question, NV Energy provided demand response results for August 18, 2020. NV Energy Comments December 23, 2020, at 13. NV Energy states that the tables show the breakout of demand response reduction between commercial and residential customers north and south as well as the irrigation customers. (*Id.*) NV Energy states the total reduction on hour 17:00 from a demand response event is 178 MW, which includes the IS-2 irrigation reduction and notes that the second and third hour traditionally see a lesser effect. (*Id.*)

NPC DR	**Hour Ending**				
	17:00	**18:00**	**19:00**	**20:00**	**21:00**
Residential Reduction (MW)	**138**	**83**	**42**	**-44**	**-22**
Commercial Reduction (MW)	**16**	**11**	**6**	**0**	**0**
Total Load Reduction in South (MW)	**154**	**94**	**48**	**-45**	**-22**

SPPC DR	**Hour Ending**				
	16:00	**17:00**	**18:00**	**19:00**	**20:00**
Residential Reduction (MW)	**10**	**8**	**4**	**-2**	**-1**
Commercial Reduction (MW)	**5**	**3**	**1**	**0**	**0**
IS-2 Reduction (MW)	**13**	**13**	**13**	**0**	**0**
Total Load Reduction in North (MW)	**27**	**24**	**18**	**-3**	**-1**

Staff's Comments

Staff states that it believes that NV Energy needs to expand on the information provided regarding its demand response air conditioning program. (Staff's November 24, 2020, Reply Comments at 9.)

Staff questions whether there was "demand response fatigue" occurring during the week of August 17, 2020, when NV Energy really needed the capacity from its demand response program because NV Energy began calling on its demand response program in June 2020, but the system peak occurred in the latter half of August 2020. (*Id.*) Staff states that it is unclear from NV Energy's comments whether, after a long summer of demand response events (especially given that more people were home because of the COVID-19 pandemic), there was a higher percentage of non-participation/overriding occurring during the week of August 17, 2020. (*Id.*)

Staff states that there could be a need to review the capacity associated with the demand response program (like what occurred with the solar generation capacity in the ESP Update in Docket No. 20-09002) if the system peak occurs late in the summer period. (*Id.*) Staff further states that NV Energy should provide information on whether there are free-rider customers in the program, who are using NV Energy's smart thermostat technology but are not participating in demand response events. (*Id.* at 11.)

Commission Discussion and Findings

The Commission finds that demand response plays an important role in ensuring energy supply reliability. During the workshop and in comments filed on December 23, 2020, NV Energy indicated that it was able to call on 178 MW of demand response during hour 17:00 on August 18, 2020. This included approximately 13 MW of demand response attributable to IS-2 customers. The DSM plan included in Docket No. 19-07004 and ESP Update included in Docket No. 19-08034 provided the combined Summer 2020 demand response total for NV Energy's energy supply planning purposes. Based on those filings, NV Energy was planning on the availability of up to 188 MW in demand response for the month of August 2020.

NV Energy also indicated that on August 18, 2020, it called on demand response from all customers at the same time, which produced a larger load reduction. Based on the information provided, NV Energy's demand response resources appear to have responded at a level contemplated by the plans filed in Docket Nos. 19-07004, 19-08034, and 20-07004. The Commission also finds that the demand response capacity reduction on August 18, 2020, demonstrated that NV Energy can effectively rely on demand response in an all-at-once call as needed.

The 2020 Combined DSM Update Report filed in Docket No. 20-07004 includes a target total demand response capacity of approximately 216.3 MW for 2021. This may be aggressive considering the lingering impact of COVID-19 social distancing protocols; however, NV Energy should make its best effort to reach this target. The system benefits were amply demonstrated in August 2020.

NV Energy should continue to evaluate the capacity assigned to demand response, customer participation and response, and free-ridership in future Annual DSM Update Reports, ESP Updates, and IRP filings. At the December 16, 2020, workshop, NV Energy indicated that it did not intend to file any updates to the demand response management program until its next triennial IRP, which will be filed in June 2021. The triennial DSM Plan included in the IRP should provide opportunities for NV Energy, other parties, and the Commission to evaluate the demand response product offerings contained in that plan and the potential to rely on additional demand response capacity reductions for the purposes of the energy supply plan and loads and resources forecasts.

Expanded demand response programs or product offerings may also be considered in future alternative ratemaking plans that NV Energy may file, including alternative incentives for both NV Energy and its customers to effect greater participation and grid benefits.

E. Utility Information Dissemination and Communications Process

Introduction

Communication between a utility and its customers is crucial during energy events and curtailment. The Commission does not have specific regulations governing how NV Energy communicates curtailments to customers facing curtailment, and there is no prescribed communications plan for notifying affected customers. Additionally, there are no regulations nor plans pre-identifying the order in which NV Energy will curtail customers in an emergency such that customers will know the order of curtailments ahead of time.

Participant Comments

NV Energy's Comments

NV Energy states that the scarcity of supply led to EEA and energy conservation requests to customers in August 2020. (NV Energy's October 5, 2020, Comments at 1.) NV Energy states that an EEA is a term defined by NERC to communicate energy emergency conditions, such as when contingency reserves drop below specified levels. (*Id.*)

NV Energy states that there are four levels of EEA. (*Id.*) NV Energy explains that EEA0 is considered normal and that EEA1 means that all available generation resources are committed to meet firm load, firm transactions, and reserve commitments. (*Id.* at 1-2.) NV Energy states that under EEA1, non-firm wholesale energy sales are curtailed. (*Id.* at 2.) NV Energy further states that, for EEA2, a BA is no longer able to provide its expected energy requirements and is energy deficient but is still able to maintain minimum contingency reserve requirements. (*Id.*) NV Energy states that, for EEA2, the BA must implement its operating plans to mitigate emergencies and put load management procedures in effect. *(Id.*) NV Energy states that, for EEA3, firm load interruption is imminent or in progress and the BA also is unable to meet contingency reserve requirements. (*Id.*) NV Energy provides that before requesting an EEA3, the BA must ensure that all available generation units capable of being online are online and must activate DSM. (*Id.*)

NV Energy states that Nevada experienced EEA events on August 17, 18, and 19, 2020, which corresponded with the calling of energy conservation requests on those dates. (*Id.*) On August 17, 2020, NV Energy declared an EEA1 at 17:55, which it updated to an EEA0 by 19:25. (NV Energy's November 6, 2020, Comments at 2.) NV Energy states that on August 18, 2020, the Reliability Coordinator ("RC West") declared an EEA1 at 12:27 that it updated to an EEA3 at 15:30. (NV Energy's October 5, 2020, Comments at 2.) NV Energy further states that at 20:33 on August 18, 2020, RC West moved to EEA1 and then to EEA0 at 21:31. (*Id.*) NV Energy states that on August 19, 2020, RC West declared an EEA1 at 12:22, which it updated to an EEA0 by 19:20. (*Id.*)

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NV Energy states that beginning on August 17, 2020, and continuing through August 19, 2020, it conducted the following outreach to its customers: contacting large end-use customers for opportunities to decrease demand through voluntary load reduction and/or through customer-owned generation; contacting customers taking service on tariff rate schedules that contemplate voluntary load reduction; contacting DOS customers to confirm that their loads and resources were in balance and not leaning on NV Energy's power supply resources; and issuing energy conservation requests to the public to achieve load reduction through customer behavior. (*Id*. at 5.) Specifically, NV Energy states that on August 18, 2020, it conducted outreach to industry stakeholders within its BA. (NV Energy's October 5, 2020, Comments at Ex. 1.) NV Energy also states that from 12:00 p.m. to 2:00 p.m. on August 18, 2020, NV Energy issued a public plea for energy conservation for the time between 2:00 p.m. and 9:00 p.m. that day. (*Id.* at Ex. 1.) NV Energy further states that, similar industry outreach occurred from 9:00 a.m. to 5:00 p.m. on August 19, 2020, and public pleas for conservation again occurred from 12:00 p.m. to 2:00 p.m. on August 19, 2020. (*Id.*)

NV Energy states that six of its transmission customers experienced a supply shortage of greater than 10 MW in any hour during the week of August 17, 2020. (NV Energy's October 21. 2020, Comments at 8.) Going forward, NV Energy states that it has developed an internal tool to identify, in real time, energy imbalances that are occurring with its transmission-only customers. NV Energy provides that this tool will equip it with the ability to notify these customers when they are relying on NV Energy's system to serve their load. (*Id.*)

NV Energy further explained its interactions with its 704B and transmission customers at the December 16, 2020, Workshop. (Tr. at 82-83.) NV Energy states that its Network Operating Agreement with its transmission customers provides some limitations as to the extent that transmission customers can utilize the ancillary services in NV Energy's OATT. (Tr. at 82.) NV Energy states that pursuant to the Transmission Reduction Plan, NV Energy will notify a customer if they are short in any way, and NV Energy will ask that customer to reduce their load. (*Id.*) NV Energy stated at the Workshop that "[t]hey have one hour to supply their reserves and to get their energy supply back up before we can implement an actual curtailment." (Tr. at 82-83.) According to NV Energy, pursuant to its Network Operating Agreement, its transmission customers have one hour only to lean on the utility or to utilize ancillary services in Schedules 4, 5, and 6 of the OATT before NV Energy can implement the Transmission Reduction Plan. (Tr. at 83.)

NV Energy also discussed the internal tool that it has developed to identify in real time where imbalances are occurring and which customers are causing the imbalances on NV Energy's system. (Tr. at 89.) NV Energy explained that this a real-time tool that shows the schedules of its transmission customers versus the customers actual loads. (*Id.*) Prior to the August 2020 events, NV Energy did not have such a tool. (*Id.*) In response to a question from Staff about whether this new tool showed data based on provider or individual customer level, NV Energy stated that the tool breaks down the information by each customer such that NV Energy knows, for example, which 704B customer is causing an imbalance. (Tr. at 89-90.)

In response to Commission questions as to whether NV Energy reached out to its transmission customers to conserve energy during the week of August 17, 2020, and whether the customers heeded that request, NV Energy stated that it reached out to customers, but it did not curtail any customers. (Tr. at 63-64.)

In addition to the information NV Energy provided in the record, the Commission did a limited review of media (newspapers and television) coverage of the calls for customer conservation, as well as NV Energy's direct communication with customers regarding the calls for public conservation. Through its limited review, the Commission found that the media was reporting NV Energy's calls for public conservation at approximately 11:00 am to 11:30 am on August 18, 2020. In other words, the media was reporting NV Energy's requests for conservation about 2.5 hours prior to the time it was asking for conservation (from 2:00 p.m. to 9:00 p.m.). However, based on the Commission's research, NV Energy's Twitter account did not post an announcement until 2:46 p.m. on August 18, 2020, which stated: "To offset energy supply issues caused by record-breaking heat throughout the Western U.S., NV Energy is asking customers to conserve energy 8/18 & 8/19 from 2-9 pm." In other words, it appears that NV Energy did not use social media to post alerts to customers until after the time in which it was asking that customers conserve energy.

NV Energy's Facebook account indicates that the first posting to conserve occurred on August 18, 2020, at 11:26 am. This is consistent with the media reporting noted above. However, numerous customers posted complaints on Facebook about receiving automated calls to conserve beginning approximately 10:00 p.m. on August 18, 2020, through approximately 3:15 a.m. on August 19, 2020. NV Energy responded that this was due to a programming error that they have corrected. It appears that the calls were for conservation for August 18 and 19, 2020.

Tenaska's Comments

Tenaska states that if NV Energy is unable to provide ancillary services pursuant to its OATT or if NV Energy determines that resource deficiency caused by a 704B customer is affecting reliability of NV Energy's transmission system, then NV Energy has the authority to implement load-shedding procedures as set forth in the Network Operating Agreements executed by 704B customers. (Tenaska's December 11, 2020, Comments at 6.) Tenaska further states that these load-shedding procedures are set forth in the "Transmission Reduction Plans" agreed to by NV Energy and its 704B customers. (*Id.*) Tenaska provides that the execution of a Transmission Reduction Plan with NV Energy is a condition of the 704B customer obtaining final approval form the Commission of its application to exit NV Energy's system pursuant to NRS Chapter 704B. (*Id.*)

Tenaska states that NV Energy did not implement firm load-shedding procedures for its native load customers, nor did NV Energy call on its network customers to implement load-shedding procedures pursuant to the Network Operating Agreements and Transmission Reduction Plan in place between NV Energy and each of its network customers. (*Id.* 8.)

BCP's Comments

BCP suggests that a potential load-shedding program should be explored with large commercial customers, including DOS customers as a mitigation measure. (BCP's November 24, 2020, Comments at 3.) BCP states that such a program could pay these customers to drop load in the event of an emergency as NV Energy experienced during the week of August 17, 2020. (*Id.*)

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Staff's Comments

Staff's November 24, 2020, comments seek clarification as to customer interactions for DR programs. (Staff's November 24, 2020, Comments at 9.) Staff notes that NV Energy needed its capacity from the DR programs. (*Id.*) Staff also asked whether there was a higher percentage of non-participations in the program during the week of August 17, 2020. (*Id.)*

Commission Discussion and Findings

The Commission is concerned about NV Energy's communications and interactions with its customers during events like the event that occurred on August 17, 2020. NV Energy did engage with its customers during the event that occurred on August 17, 2020, but it appears that NV Energy may be able to improve its communications and utilize the tools at its disposal more effectively.

With respect to the communications during the August 2020 event, the record is unclear as to how effectively NV Energy communicated with customers in the context of this event. In the timeline of events provided as Exhibit 1 in NV Energy's comments dated October 5, 2020, NV Energy was aware by 3:00 p.m. on August 17, 2020, at the latest, that it could not procure sufficient resources in day-ahead trading and had the potential to need to curtail load on August 18, 2020.

Several DOS customers, including MGM and Caesars, assert that NV Energy asked them to conserve/curtail. However, electric suppliers for those customers may not have been informed of conservation requests and possible impending curtailments. Tenaska, a provider for several transmission customers, indicated that it was not specifically alerted.

It appears that NV Energy may not have used social media effectively, as NV Energy posted some notices after the start of the period for which it was requesting voluntary conservation. Direct customer communications could also be more effective. NV Energy sent some emails, texts, or phone calls prior to the conservation period and others after the start of the conservation period. The reported robocalls late in the evening and early morning hours did not assist in the messaging. However, the communication with the news media appears to have occurred earlier in the day, prior to the 2:00 p.m.to 9:00 p.m. conservation period. Even these communications, though, did not begin until approximately 11:30 a.m. to 12:00 p.m. for requests to conserve beginning at 2:00 p.m. that day. A two-hour time window requesting customers to conserve and prepare to potentially be without power in the heat of a Las Vegas August is very narrow and may not be sufficient for customers to implement conservation measures. *e.g.*, if they had left their home for the afternoon or need additional time to make other preparations such as filling coolers with ice to store food. No discussion was presented with respect to the potential impact on Green Cross customers.

Fortunately, NV Energy did not ultimately need to shed load during the August 2020 events. If NV Energy had needed to curtail customers, there is no prescribed communications plan to notify affected customers of impending power outages resulting from EEA declarations. For example, there is not a standing system to email, text, or call customers before the curtailments occur unless the customer has set up an on-line account via the "MyAccount" on-line customer portal. This may leave NV Energy with only informal and possibly last-minute options to alert customers of emergency conditions, such as alerting all customers of forthcoming curtailments on social media rather than contacting those affected customers directly ahead of the power outage.

There are no regulations or other requirements pre-identifying the order of curtailments for an emergency event such that customers know ahead of time whether they might be the first to be curtailed. Such predetermined curtailment priorities during emergency shortages could allow customers with lower priority, *i.e.*, those who would be first to be curtailed, to plan for blackouts whenever NV Energy declares an emergency shortage event. For instance, NAC 704.501, "priorities in curtailment of service," outlines the order of curtailments for natural gas customers. In contrast to electricity customers, natural gas customers generally know that certain customers will be first to be curtailed while others, such as high-priority customers like hospitals, will be the last to face curtailments.

NV Energy does have the ability through its MyAccount on-line customer account portal to notify those customers who have opted to sign up for this feature. However, NV Energy does not require customers to create an on-line account, and some customers may elect not to have NV Energy contact them by voice or text. Customers may not read e-mail notifications timely, and, while MyAccount clearly applies to residential customers, the extent to which commercial and industrial customers utilize it is unknown. The most recently filed annual Service Quality and Metrics Report in Docket No. 21-04001 disclosed that only 62.72 percent of customers have created an on-line MyAccount, and it is unknown how many of these customers have opted to allow phone contact.

NV Energy developed its Natural Disaster Protection Plan ("NDPP"), including its Public Safety Outage Management ("PSOM") plan, pursuant to the regulations promulgated in Docket No. 19-06009. While this plan is directed at preventative de-energization during periods of elevated weather-related fire risks, the communications framework could be leveraged and adapted for use in an extreme heat system resource event as well. Indeed, events resulting from extreme heat related to climate change might qualify for treatment under the NDPP statute. The NDPP regulations or Plan may warrant inclusion of comfort centers where customers can charge cellular phones or obtain water and ice, for example. "Heat wave" is included in the definition of a natural disaster in the draft regulations. The regulations call for communications plans for customers, stakeholders, and communication infrastructure providers. The approved PSOM plan also includes timelines for notifications. Notably, even if a PSOM event is initiated, it can and has been cancelled if conditions change. The PSOM provides the opportunity for customers to better prepare for an outage. The primary difference is that, unlike a PSOM event, customers have the ability through conservation and demand response to influence whether or not an extreme heat system resource event outage in fact occurs.

NV Energy should consider conducting or updating customer surveys and focus group studies with an emphasis on extreme heat system resource events like those of August 18 and 19, 2020, to evaluate the effectiveness of its communications and elicit feedback that can be used in refining its communications. Topics could include:

1. When NV Energy should initiate communications with customers;
2. How frequently NV Energy should update customers (with an eye to preventing communication "fatigue");

3. Whether the customers actively conserved or participated in demand response in response to NV Energy's call for conservation; and

4. What other information would be useful on NV Energy's website (EEA status, for example).

Finally, Nevada does have regulations requiring electric utilities to report "significant service outages" to the Commission after the fact. NAC 704.2565(1) defines reportable electric service outages as a forced outage of at least 3,000 customer-hours or any outage lasting more than 10 hours that affects at least 50 customers. Thus, NV Energy must report to the Commission any extended or large customer outages.[100] These reports can provide forensic data to assess the causes of outages and to identify "lessons learned" to prevent similar outages from occurring in the future. However, the regulations do not require NV Energy to report resource shortage events that resulted in "close calls" but not significant outages.

[100] For the current year, Docket No. 21-01001 contains all utilities' outage reports.