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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

IN THE MATTER of the Application of NEVADA POWER COMPANY, seeking approval of the 2016-2035 integrated resource plan, its three year Action Plan for 2016-2018, which include a pilot subscription solar program, the acquisition of a 25 percent share of the Silverhawk Generating Station and reliance on market purchases to meet its remaining near- term open position.	Docket No. 15-07___

VOLUME 12 OF 18

IRP SUPPLY SIDE PLAN
AND TECHNICAL APPENDIX

NEVADA POWER COMPANY d/b/a NV ENERGY 2015 INTEGRATED RESOURCE PLAN

SUPPLY SIDE PLAN, TRANSMISSION PLAN, ECONOMIC ANALYSIS, AND FINANCIAL PLAN

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SECTION 1. INTRODUCTION

This volume of the Nevada Power Company d/b/a NV Energy ("Nevada Power", "NPC," or "Company") 2016 – 2035 Integrated Resource Plan (the "2015 Resource Plan" or "2015 IRP") presents the Supply Side Plan, the Economic Analysis used to select the Preferred Plan and the Financial Plan.

Nevada Power is guided by six core principles. The Company's 2015 Resource Plan is consistent with these core principles: customer service, employee commitment, environmental respect, regulatory integrity, operational excellence, and financial strength. As such, the Company's 2015 Resource Plan is consistent with Nevada Power's strategic plan and is supported and endorsed at the highest levels of NV Energy.

Assembly Bill 498 from the 78th Session of the Nevada Legislature

The planning, development and preparation of an integrated resource plan ("IRP") filing and an emissions reduction and capacity replacement plan filing begins months before the filing date. Essential inputs such as the load and price forecasts are finalized as much as 120 days prior to the filing date. Production cost modeling, the associated economic analysis, and the present worth of societal cost analysis are well underway with interdependent portions completed approximately 45 days before the filing.

When the Company began preparing the filing, it originally planned to develop a subscription solar program that had four separate tranches: 5 megawatts ("MW"), 10 MW, 10 MW, and 10 MW. The Company also planned to use capacity provided pursuant to NRS 704.7316(2)(b)(6) to develop the program.[1] The loads and resources tables, production cost modeling, capital expense recovery modeling, economic analysis, and present worth of societal cost analysis all include the addition of 5 MW of photovoltaic generation in December 2016, 10 MW in December 2017, 10 MW in December 2018, and the final 10 MW in December 2021. These generating additions are embedded in all alternative plans analyzed below. Because they are embedded in all alternative plans, they do not impact the relative economic and societal worth analysis.[2] Similarly, the Company planned to address other elements of NRS 704.7316 (the emissions reduction and capacity replacement plan) pursuant to the Commission's order in Docket No. 14-05003.

On June 1, 2015, the last day of the 78th Session of the Nevada Legislature, Assemblyman Hambrick introduced Assembly Bill 498 ("AB 498"). Several of the Company's customers had expressed concerns about the costs associated with implementing the final elements of NRS

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[1] NRS 704.7316(2)(b)(6) provides for the construction or acquisition and ownership by the Company of 50 MW of renewable energy facility. In Docket 14-05003, the Commission authorized the Company to construct a 15 MW renewable energy facility located at the Nellis Air Force Base. There remains 35 MW of renewable energy facilities to be constructed or acquired and owned by the Company pursuant to NRS 704.7316(2)(b)(6).

[2] The economic and societal costs that the Company actually experiences will differ from the analysis for a number of reasons including the fact that actual fuel and purchase power costs will differ from those modeled in the filing. The projects required by NRS 704.7316 eventually will be constructed. Thus, while the economic analysis and societal costs will differ from that included in the filing because of AB 498, the economic and societal benefits associated with the projects eventually will be realized by the Company's customers.

704.7316. Accordingly, at the request of several of the Company's largest customers, the Company assisted in the preparation of the legislation. The Assembly and the Senate both approved the measure the day it was introduced. The Bill was signed by the governor on June 11, 2015. The legislation requires that Nevada Power demonstrate "to the satisfaction of the Commission" the need for the capacity to fill the final elements of NRS 704.7316, In light of the legislation, through this filing and the related first amendment to the Emissions Reduction and Capacity Replacement Plan ("ERCR"), the Company is not moving forward with three elements of NRS 704.7316: the construction or acquisition of 54 MW of generating capacity pursuant to NRS 704.7316(2)(c), the construction or acquisition of 35 MW of renewable energy facilities pursuant to NRS 704.7316(2)(b), and the issuance of a request for proposals in 2016 for 100 MW of renewable energy pursuant to NRS 704.7316(2)(b)(3).

The Company does intend to move forward with those projects through future filings when, consistent with AB 498, it can demonstrate, to the satisfaction of the Commission that it has a need for the specific generating capacity. However, because of the timing of the adoption of the legislation, the Company was not able to adjust certain elements of this filing. For instance, each of the alternative plans contains "placeholders" for the generating capacity referenced in AB 498. For instance, a generic 54 MW of gas–fired reciprocating engines are embedded in the production cost and capital expense recovery modeling as a placeholder addition in May 2018. Similarly, a generic 100 MW renewable energy facility addition is embedded in the production cost and capital expense recovery modeling as a placeholder addition in December 2017. Also, the production cost and capital expense recovery modeling includes the four tranches of renewable energy additions discussed above. Consistent with AB 498, the Action Plan does not include requests to for approval of these resources.

The Company was not able to remove each of these projects from the analysis performed for this 2015 IRP. Thus, the filing continues to reference these projects and, as noted above, they are deeply embedded in the production cost modeling, capital expense recovery modeling, the economic analysis, the present worth of societal costs, the loads and resources tables, and the renewable portfolio compliance plan. Also as noted above, because these placeholders are included in all alternative plans, they *do not* affect the overall conclusions of the economic analysis included in the filing. The economic analysis and the present worth of societal cost analysis measure relative differences between alternative plans. Because these projects are included in each alternative plan, the production cost and capital expense recovery associated with each project does not affect the relative analysis.

Through this filing, the Company *is* requesting permission to proceed with a 5 MW pilot subscription solar program that that will be paid for exclusively by customers who enroll in the program. This program, which will not be included in the first amendment to the ERCR, provides an alternative for customers who do not have the opportunity to install rooftop solar on their premises. Despite the Company's open capacity positions throughout the Action Plan period, it *is not* requesting permission to expand the program to include three additional 10 MW tranches. Equally important, the Company *is not* seeking permission to add 54 MW of non-technology specific generating capacity. Nor is the Company seeking permission to add 100 MW of renewable energy pursuant to NRS 704.7316(2)(b)(3). The Company will address the resources and projects identified in AB 498 through subsequent integrated resource plan amendments or integrated resource plan filings.

Other Resource Planning Challenges

Nevada Power assembles detailed plans to meet the projected needs of its customers and compiles those plans into triennial Integrated Resource Plan filings for approval by the Commission. The Company responds to resource planning challenges, be they from unforeseen circumstances in the load forecast or the broader economy, revisions or additions to legislative policy or regulations, advancements in technology and gains in efficiency, or changes in customer's expectations. In addition to load forecast uncertainty resulting from pending 704B applications, the Company, the Commission, and the State currently face challenges related to jointly planning Nevada Power and Sierra's resources and compliance with potential future "Clean Power Plan" regulations.

Joint Planning. Regarding Joint Planning, in its report in the investigation regarding the utilization and allocation of costs and benefits of ON Line capacity (Docket No. 14-04039), the Commission required that Nevada Power and Sierra address joint planning in a filing to be made in early 2015 recommending whether the two utilities should be merged into a single legal and regulatory entity. In that filing, the Companies addressed alternatives for joint planning under both a merger and no-merger scenario. Given the recommendation in Docket No. 14-04039 that the utilities remain separate legal and regulatory entities and jointly dispatch the two systems utilizing the ON Line, Nevada Power addresses the benefits and challenges of joint planning below:

The Companies engage in a limited form of joint planning currently, preparing a single loads and resources table for use in day-ahead planning and where appropriate (*e.g.*, in proposing to construct the Ely Energy Center and the ON Line) use an ad hoc joint planning approach to evaluate resource options. A more formal version of joint planning as separate utilities will require an additional framework under which the need and timing for new resources is identified and the methodology whereby the fixed costs of these new resources will be allocated between the utilities is established, preferably in advance.

In a two-utility framework, the focal point of the analysis is the aggregated system (*i.e.,* coincident) peak load. This requires the development of a single, long-term, coincident peak load forecast. Coincident peak planning provides the advantage of some system load diversity resulting in lower overall peak demands than planning for each system independently. Moreover, coincident peak planning is reasonably accomplished using existing protocols and is consistent with current planning protocols used for each stand-alone utility. Currently the peak load diversity between Nevada Power and Sierra is estimated to be less than 75 MW. At its most basic, using a pure loads and resources approach, planning under a two utility framework can be performed similarly to planning in a single utility framework. The primary complication involves determining the appropriate cost allocation methodology to use for the addition of new resources.

Planning for new resources jointly, while maintaining two separate utility entities, will require agreement on planning assumptions and allocation methodologies. These assumptions and methodologies may have a range of reasonableness and failure to establish agreement on the front end could contribute to protracted disagreement after expenditures have been made.

Capital Cost Allocation under Joint Planning. A methodology to appropriately share the capital costs between the utilities should be established before the expenditure is made. It would be advantageous if the methodology was straight-forward and could be applied simply to all expenditures necessary for a new resource, held constant for the life of that resource. Agreement prior to deploying capital will facilitate an objective planning analysis that can focus on determining the least cost solution without regard to location and or ownership. Reasonable alternatives that can assure proper up-front capital allocation and recovery and that prevent any potential for stranded investment include:

> **Open Capacity Position Ratio**. The ratio of open capacity position ("Open Position") at peak at the time the new resource comes into service could be utilized. This allocation would be set at the time the new resource is approved by the Commission and should remain fixed over the life of the asset. Variations in utilization (variable costs) will be accounted for separately as proscribed in the approved Joint Dispatch Agreement.
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> **Peak Load Ratio Share**. Projected peak loads at time of a new resource addition could be utilized to allocate capital costs. Agreement on the specific peak period to be used (historical or projected) would be required. Additionally, coincident peak allocation methodologies such as a 4 coincident peak ("CP") or a 12 CP methodology could be employed.
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> **Projected Energy Ratio Share**. Utilizing the forecasted demand for energy, a ratio could be developed to allocate capital costs based on overall energy demand. A time horizon would need to be agreed upon, as well as detailed assumptions for future energy efficiency and other load forecast impacts. This ratio potentially could be calculated for the projected life of the new resource.
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> **Alternate Investments**. An approach of alternating new resource additions, (*e.g.*, Nevada Power first, then Sierra, then Nevada Power, etc.) could be utilized. Significant challenges determining the size and timing of the new resources would need to be addressed and agreed upon. For example, would some level of Open Position be acceptable or would each utility be required to completely close its projected Open Position?
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> **Owner by Geographic Territory**. Maintaining ownership based on location could be maintained. This requires additional transmission system modeling to identify overall lowest cost resource additions and is complicated if a resource opportunity outside both territories is identified. This methodology could potentially facilitate least cost siting on next resource but may bias rate base toward one utility with unbalanced capital deployment. Depending on resource type and local permitting, infrastructure, or similar variables, this methodology could result in one utility bearing an unbalanced burden of capital costs while the other relies exclusively on energy produced by the other. This

concern can be addressed through the allocation process applied to joint dispatch transactions, however.

Other Joint Planning Considerations. Given the relative size of the two systems, determining the appropriate Open Position trigger and the acceptable size of new increments of resources is challenging. Planning for the needs of the joint system allows for the potential to add larger, more efficient building blocks of resources, but it may be difficult to determine the ratio of the benefits of such an approach.

Overall, coordinated planning offers the opportunity for benefits from building a more efficient and timely deployed resource portfolio. However, detailed planning assumptions and guidelines need to be established up front with significant collaboration and agreement from stakeholders guided by the Commission.

Clean Power Plan

Later this summer, the Environmental Protection Agency ("EPA") will issue a final rule/standard aimed at the reduction of carbon emissions from existing power plants. This standard, known as the Clean Power Plan, is being developed under Section 111(d) of the Clean Air Act.

The original draft Clean Power Plan, released in June 2014, established state-by-state carbon intensity/emissions rate reduction targets, and it offered a framework under which states could meet those targets. The draft of the Clean Power Plan provided for a number of options to cut carbon emissions, called "building blocks," and set state emissions rate targets by estimating the extent to which states could implement each of them. Renewable energy resources accounted for one of the building blocks, alongside nuclear power, efficiency improvements at individual fossil fuel plants, shifting generation from coal to natural gas, and adoption of energy efficiency initiatives.

Targets in EPA's draft plan differed across states, presumably because of each state's mix of electricity-generation resources, as well as variances in technological feasibilities, costs, and emission reduction potentials of each building block. The emission rate targets set for Nevada were 697 lb/MWh by 2020 and 647 lb/MWh at 2030. These emission rate targets are well below the emission rates associated with existing coal fired units as well as new combined cycle natural gas units.

According to EPA, states have the ability to combine any of the building blocks in a flexible manner to meet their targets. Additionally, states can also join together in multi-state or regional compacts to find the lowest cost options for reducing their carbon emissions.

The EPA accepted public comments on the draft Clean Power Plan until December 1, 2014 and over four million responses were received. On June 1, 2015 the EPA sent the 111(d) rule to the White House Office of Management & Budget ("OMB") for review. OMB has up to 90 days to conduct its analysis, and it is currently expected that EPA will publish the final rule in August 2015.

Based on EPA statements subsequent to the close of the public comment period, the final rule may contain some significant changes, including modification of certain state targets and building block assumptions. The Companies will need to revisit all assumptions regarding future 111(d) planning after the final rule is released. At this time, the Companies assume the effective date of the rule begins on January 1, 2020; however, this rule will likely be subject to extensive litigation which could impact the compliance timeline.

The EPA did not clearly indicate in the proposed Clean Power Plan how new natural gas combined cycle units will be included within the rule. Discussions over the past year with EPA representatives and other stakeholders have brought to light concerns that if new natural gas combined cycle units are not included under 111(d) in a state's compliance plan, such new units could be brought into a state and effectively displace existing 111(d) impacted units, thereby creating stranded/under-utilized investments. For example, in Nevada, large customers might pursue a 704B application, build or buy energy from a new natural gas combined cycle facility unburdened by the Clean Power Plan regulation, leaving remaining NV Energy customers burdened with 111(d) compliance cost obligations.

Supply Side Plan

Conventional Generation. With the Commission's leadership and support, Nevada Power has reduced its reliance on volatile wholesale markets in recent years. With the near term opportunity to add modest renewable (ERCR Filing) and conventional resources, Nevada Power currently projects sufficient Company owned and/or controlled generation to meet most of its customers' near term needs. However, thoughtful planning to maintain resource adequacy over the longer term and in a variety of planning scenarios is critical to controlling the future cost of energy for customers and maintain a reliable energy system.

Utilizing the results of the long-term load forecasts, the demand-side management plan ("DSM Plan") and the renewable energy plan, Nevada Power identified the Company's resource requirements over a full thirty-year planning period. This analysis indicates that Nevada Power has a significant resource need in 2018-2020, depending on the load forecast scenario. The Preferred Plan includes the Company's acquisition of Southern Nevada Water Authority's ("SNWA") share of Silverhawk and the commitment of minimum expenditures to preserve the option to construct a block of combined-cycle combustion turbines (700 MW) no sooner than 2020. Due to significant load uncertainty, the Company is only proposing to acquire Silverhawk and is not requesting full authority to proceed with the construction of any generating units at this time. The Company is limiting its Action Plan request to authorization to expend sufficient funds, approximately $2.4 million, to preserve its ability to construct a new gas fired unit in 2020 once the load forecast becomes more certain. This incremental approach offers a preferred plan that cost effectively meets the immediate resource planning needs that exist in all load forecast scenarios and maintains the flexibility to respond to load growth effectively should it materialize.

Renewables. The Renewable Portfolio Standard ("RPS") requires the Company "to generate, acquire or save electricity from portfolio energy systems or efficiency measures" in amounts that are prescribed by statute. See NRS 704.7821 (as amended by SB 358, 2009 Session).[3] In 2009 Nevada's aggressive RPS was amended to increase the percent of retail load that must be met with renewable resources. In 2011 the RPS increased to 15 percent of retail load, and will grow to 18 percent in 2013, 20 percent in 2014, 22 percent in 2020, and 25 percent in 2025. The Company is well poised to comply with the RPS through the Action Plan period with its existing portfolio of diverse renewable resources. Nevada Power will continue to monitor execution of previously approved renewable plans and adjust to any changes in the delivery of renewable energy and portfolio credits from its existing portfolio of renewable projects and proposed projects

Transmission. Set forth below is Nevada Power's twenty-year plan for meeting the transmission needs of its native load customers, as well as third-party service requests. The Transmission Plan is built upon the load forecasts prepared for this filing, system characteristics (*e.g.,* existing generation facilities in Section 2A. of this volume), and existing and future transmission facilities and obligations as described below. Based in part on these key system characteristics, the Transmission Plan examines the capabilities of the existing transmission system, allowing the Company to determine the need for and timing of additional transmission facilities. In addition, the Transmission Plan includes proposals to address the development of Nevada's renewable resources for both internal consumption, and for import and potential export to other markets per Assembly Bill 387 (2009 Legislature) and the Commission's rulemaking Docket No. 09-07010. Nevada Power's continued participation in WestConnect and interaction with regional and national regulators is also discussed.

Nevada Power's Transmission Plan does not include requests to invest in new transmission projects.

Nevada Power and Sierra are members of the WestConnect Steering Committee and WestConnect Transmission Planning Committee, and are seeking Commission authorization to fund the continued participation in WestConnect during the 2016-2018 Action Plan Period. The Action Plan budget reflects an increase in the cost of participating in WestConnect due to the mandates of FERC Order 1000. Nevada Power's share of these costs is estimated as $952,000 during the Action Plan period.

Economic Analysis and the Preferred Plan

The 2015 Resource Plan evaluates the present worth of revenue requirements ("PWRR") of various plans in order to determine which alternative has the lowest PWRR over 20 and 30-year planning horizons. The Company's IRP decisions must take into account an assessment of risk with respect to cost, reliability, finances and exposure to fuel and power price volatility. The intent of the analysis is to determine the alternative plan that will provide the greatest savings to Nevada Power's customers while also meeting the RPS and environmental requirements and considering other relevant factors such as fuel diversity, operational flexibility, and related economic planning considerations.

[3] This filing does not address changes implemented during the 2013 Legislative Session, for which rule making is still pending.

Nevada Power developed three alternative plans for meeting its projected long-term needs for incremental capacity and energy. The Company evaluated the three alternative plans with sensitivities around high, low and 704B low load forecasts, high and low fuel and purchase power price forecasts, and high, low, and Clean Power Plan carbon forecasts. In addition, an economic analysis of the Preferred and Alternate Plans, with and without external system power sales, was performed.

The Preferred Plan centers on the acquisition of SNWA's share of Silverhawk Generating Station and minimum investment necessary to preserve the option to build new gas-fired generation by 2020. All of the alternative plans include additional placeholder gas fired units in 2022 (186 MW), 2023 (706 MW), 2027 (372 MW) and 2030 (283 MW) in the base load scenario. The Company is not requesting authority to proceed with the construction of any of these placeholder gas-fired generating units at this time, limiting its Action Plan request to authorization to expend sufficient funds to preserve the option of construction. By focusing on preserving future resource options, Nevada Power maintains least cost options for customers while continuing to limit customers' exposure to potentially volatile energy markets.

Financial Plan

The analysis contained in the Financial Plan shows that the Company has the financial capacity to finance the Preferred Plan, both as modeled in the Financial Plan and as specified in the Action Plan.

SECTION 2. SUPPLY SIDE PLAN

A. GENERATION

1. EXISTING AND PREVIOUSLY APPROVED GENERATION

(A) SUMMARY

Nevada Power's net portfolio of generation capacity has increased by approximately 227 MW[4] since the Commission issued its Order (dated December 24, 2012) in the 2012 Resource Plan (Docket No. 12-06053). Pursuant to the Commission's order in Docket No. 14-05003, Nevada Power's Emissions Reduction Capacity Replacement Plan ("ERCR"), in late 2014, the Las Vegas Generating Station (formerly Las Vegas Cogeneration Station) and the SunPeak Generating Station were purchased by Nevada Power and added to its generating fleet.

An overview of Nevada Power's existing portfolio of renewable and fossil-fired generation is provided below. This section also includes an update on the Brownfield Site Selection Study, the decommissioning of Reid Gardner Station, Navajo Generation Station Retirement, the status of

[4] Summer peak capacity.

the Nellis Solar PVII Plant and an explanation of the generation technology options utilized in the expansion plan analysis for this IRP.

(B) EXISTING GENERATION

Nevada Power holds an ownership interest in 4,751 MW (total peak summer capacity) of resources composed of the following generating facilities:

- Clark Generating Station: 1,102 MW of total peak summer capacity, located in Las Vegas. Clark Station is composed of two 2x1 natural gas-fired combined cycle units (430 MW), one natural gas-fired combustion turbine unit (54 MW), and twelve natural gas-fired simple cycle combustion turbines (618 MW).

- Chuck Lenzie Generating Station: 1,102 MW of total peak summer capacity including duct burners and inlet chillers. The plant is located approximately twenty-four miles northeast of Las Vegas and is composed of two 2x1 natural gas-fired combined cycle units (551 MW each).

- Goodsprings Heat Recovery: 5 MW (summer peak) waste heat recovery project is adjacent to the Kern River Goodsprings compressor station. The unit captures heat from Kern River's natural gas-fueled compressors, and uses a separate generator to produce electricity.

- Harry Allen Generating Station: 628 MW of total peak summer capacity, located twenty-four miles northeast of Las Vegas. The Harry Allen Generating Station is comprised of the new 484 MW natural gas-fired Harry Allen Combined Cycle facility, as well as 144 MW of natural gas-fired combustion turbine peak summer capacity generated by two gas-fired turbine units (72 MW each).

- Las Vegas Generating Station: Formerly Las Vegas Cogeneration Station, is located in an industrial section of the North Las Vegas city limits just west of I-15 and has a 272 MW net generation (peak summer capacity). LV Gen Block 1 is a 1x1 combined cycle that is rated at 48 MW. LV Gen Blocks 2 and 3 are each a 2x1 combined cycle that is rated at 112 MW each.

- Navajo Generating Station: Nevada Power has rights to 255 MW of net capacity, which reflects an 11.3 percent ownership share of the Navajo Station, a 2,250 MW total net capacity facility located near Page, Arizona. The facility is composed of three similar coal-fired steam turbine units (750 MW each). The units are co-owned by a number of parties with Salt River Project serving as the operator.

- Reid Gardner Generating Station: 257 MW of total peak summer capacity, located fifty-two miles northeast of Las Vegas, one coal-fired steam turbine unit (257 MW). Nevada Power retired Units 1-3 in December of 2014. Nevada Power can store an estimated maximum of 0.8 million tons of coal on site at Reid Gardner.