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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of NEVADA POWER COMPANY d/b/a NV Energy and SIERRA PACIFIC POWER COMPANY d/b/a NV Energy, seeking approval to add 1,001 MW of renewable power purchase agreements and 100 MW of energy storage capacity, among other items, as part of their joint 2019-2038 integrated resource plan, for the three year Action Plan period 2019-2021, and the Energy Supply Plan period 2019-2021	Docket No. 18-06___

VOLUME 11 OF 18

NARRATIVE
SUPPLY SIDE PLAN, TRANSMISSION PLAN, ECONOMIC ANALYSIS, DISTRIBUTION PLANNING, AND FINANCIAL PLAN

NARRATIVE

SUPPLY SIDE PLAN

NEVADA POWER COMPANY d/b/a NV ENERGY
SIERRA PACIFIC POWER COMPANY
d/b/a NV ENERGY

JOINT SUPPLY SIDE PLAN, TRANSMISSION PLAN, ECONOMIC ANALYSIS, DISTRIBUTION PLANNING, AND FINANCIAL PLAN

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SECTION 1. INTRODUCTION

Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra" and together with Nevada Power the "Companies" or "NV Energy") are filing this first joint integrated resource plan ("2018 Joint IRP"). Senate Bill 146 from the 2017 Legislature required the Companies to file a joint plan for both utilities on or before June 1, 2018. The Joint 2018 IRP is guided by the Companies' six core principles: customer service, employee commitment, environmental respect, regulatory integrity, operational excellence, and financial strength. In addition, the 2018 Joint IRP furthers the Companies' strategic plan to double their use of renewable energy while maintaining, and not increasing, their bundled retail rates. In determining their Preferred Plan and preparing its Action Plan, the Companies developed four long-term primary expansion cases for meeting customers' demands,[1] and tested them to determine how each performed across the range of potential load, purchased power price, fuel price and carbon cost scenarios. Assuming that Question 3 is not successful in the November 2018 election, the Companies have selected as their Preferred Plan the Low Carbon Case, the centerpiece of which is:

1) The expansion of the Companies' demand side management ("DSM") programs to deliver statewide energy savings of at least 1.1 percent of the weather normalized retail sales over the Action Plan period. This building block of the Preferred Plan is addressed in the DSM Plan volumes appearing earlier in this filing.

2) The addition of 1,001 megawatts ("MW") of renewable energy sourced from six new solar photovoltaic ("PV") purchased power agreements ("PPAs") and three new co-located battery storage projects.

3) The early retirement of the North Valmy Unit 1, by December 31, 2021, provided that certain specified conditions are met; and

Residential, commercial and industrial customers have been clear that they want Nevada Power and Sierra to serve them with more renewable energy without impacting the costs they pay. Nevada Power and Sierra have listened, as is demonstrated by their strategic plan to double their renewable energy resources by 2023, without increasing bundled rates. This 2018 Joint IRP demonstrates just how the Companies intend to meet the pace of economic growth in both northern and southern Nevada, rely more on renewable energy, and keep rates low. The overarching goal of this 2018 Joint IRP is to meet growth and shrink customers' exposure to natural gas prices by delivering more low-cost renewable energy to customers.

[1] A fifth case was constructed for the purposes of short-term planning. This case was only evaluated over five years and is the Companies' preferred plan in the event voters approve Question 3 in November 2018.

Once the energy savings targets in the DSM Plan were finalized, the Companies looked wide-range of supply side investments and alternatives to increase shortfalls of electricity. The Companies analyzed and considered four alternative cases to pursue in a long-term planning scenario:

- **All Market Case**: This case adds two new solar projects, the 200 MW Dodge Flats project and the Cypress Creek - Battle Mountain Solar, 101 solar PV facility located in northern Nevada. These projects are added for the purpose of facilitating Sierra's compliance with Nevada's RPS. Outside of these supply additions, the All Market Case relies on short-term power purchases during the Action Plan Period to meet demand.
- **Renewable Case**: This case adds four new solar PV projects in addition to the 200 MW Dodge Flats and 100 MW Fish Springs Solar project for a total of six new solar projects. Those projects are: Cypress Creek Renewables' Battle Mountain Solar SP, LLC for 101 MW near Crescent Valley, Nevada; 8minutenergy's 300 MW project at the Eagle Shadow Mountain Solar Farm, Sempra's 250 MW Copper Mountain Solar 5, and the 50 MW Techren V project. The case also adds battery storage systems directly tied to the Dodge Flats, Fish Springs and Crescent Valley solar projects, consisting of a 50 MW/200 MWh battery, a 25 MW/100 MWh battery, and a 25 MW/100 MWh batter, respectively.
- **Low Carbon Case**: This case contains the same six solar projects as the Renewable Case. The Low Carbon Case proposes the retirement of North Valmy Unit 1 in December 2021, subject to specific criterion that are designed to ensure the economic and reliable operations following that retirement.
- **Development Case**: This case contains the same six solar projects as the Renewable Case as well as the retirement of North Valmy Unit 1 in 2021. It adds two additional 150 MW solar projects owned and operated by NV Energy.

NV Energy selected the Low Carbon Case as its Preferred Plan and the similar Renewable Case as the alternative plan. The Renewable Case has less impact on customers and the lowest present worth of revenue requirement. With respect to the impact on the State's economy, both cases involve an estimated $2.175 billion progressive investment in Nevada, provide an estimated 1,785 construction jobs and approximately 76 long-term jobs. Turning to the impact on the environment, the Low Carbon Case minimizes the impact of NV Energy's operations on the State, national and global environment. NV Energy selected the Low Carbon Case based the fact that the case is more closely aligned with Nevada's energy policy and delivers the services our customers value.

The 2018 Joint IRP builds on the Companies' long renewable energy record. If approved, the Low Carbon Case will add more than 1,001 MW of new solar PV to the Companies' resource portfolios, more than doubling renewable energy production by 2023 and nearly doubling renewable capacity. The estimated $2.175 billion investment will bring jobs, both construction and permanent, to

Nevada. Our development partners have signed work site agreements, ensuring that skilled Nevadans have the opportunity to perform their tradecraft. The Low Carbon Case results in only 0.5% of the energy we produce coming from coal units, while 32% will come from renewable energy.

NV Energy has an equally strong record of keeping customer costs low. The Low Carbon Case reduces the overall cost of electricity in contrast to the All Market and Development Cases. The Alternative Plan, the Renewable Case, is the lowest cost case analyzed by NV Energy. In the 10-year planning horizon, the Low Carbon Cases reduces cost by $35 million (present value) compared to the All Market Case and $52 million compared to the Development case. Over the 20-year horizon, the present value of the savings grows to $113 million and $53 million respectively. In the 30-year horizon, the present value of the savings compared to the All Market Case grow to $155 million, while the present value of the savings compared to Development Case decline to $29 million.

New generation requires new investments in transmission in order to deliver clean energy to customers. The 2018 Joint IRP proposes approximately $20 million of investment to bring the output of new solar facilities to customers. In addition, the plan proposes to expand grid improvement efforts by upgrading 230 kilovolt ("kV") transmission facilities at a cost of $720 thousand. In addition, previously approved grid improvement expenditures of approximately $40 million and $15 million of grid resilience investment will continue. These projects are all designed to improve reliability and security for customers, ensuring that the grid delivers the services customers expect when customers need those services.

By the end of 2019, the Companies will have retired or eliminated their ownership interest in all of the coal-fired generation serving southern Nevada. This IRP continues this legacy, providing a blueprint for the orderly and structured early retirement of North Valmy Unit 1, four years ahead of schedule in 2021. The plan is a responsible one, recognizing the critical services that generation located outside Winnemucca, Nevada provides to the northern Nevada bulk electric system and the role the North Valmy unit plays in serving the Carlin Trend and the economies of Humboldt, Pershing, Churchill, Lander, Eureka and Elko County. The 2018 Joint IRP bolsters generation in this part of the State with a 101 MW solar facility, coupled with a 25 MW battery storage system located in Humboldt County.

In summary, the ultimate result of this 2018 IRP, which is laid out in detail in the following volume, is the selection of the Low Carbon Case as the Companies' Preferred Plan. This selection reduces exposure to natural gas prices and reduces electricity cost compared to two of the alternatives we analyzed. In light of the environmental benefits and carbon reductions, and the nexus between the Low Carbon Case and Nevada's energy policy, NV Energy concluded that the Low Carbon Case presents the best value for customers.

SECTION 2. SUPPLY SIDE PLAN

A. GENERATION

1. EXISTING GENERATION

Together Nevada Power and Sierra currently hold ownership interests in approximately 6,011 MW (total peak summer capacity) of generation from the following electric generating facilities (figures reflect summer capacities):

- Chuck Lenzie Generating Station – Nevada Power: 1,102 MW of total peak summer capacity including duct burners and inlet chillers. The plant is located approximately 24 miles northeast of Las Vegas, Nevada, and is composed of two 2x1 natural gas-fired combined cycle units (551 MW each).

- Clark Generating Station – Nevada Power: 1,102 MW of total peak summer capacity, located in Las Vegas, Nevada. 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 12 natural gas-fired simple cycle combustion turbines (618 MW).

- Clark Mountain Station - Sierra: Two dual-fuel (gas/diesel) combustion turbines with a peak summer capacity of 132 MW. The Clark Mountain units are co-located with the Tracy Station east of Reno.

- Ft. Churchill Station - Sierra: Two natural gas-fired condensing steam turbine units located 10 miles north of Yerington, Nevada. Total peak summer capacity of these units is 226 MW.

- Goodsprings Heat Recovery – Nevada Power: Five MW of total peak summer capacity located adjacent to the Kern River Goodsprings compressor station. The waste heat recovery unit captures waste heat from Kern River Gas's natural gas-fueled compressors, and uses a separate generator to produce electricity.

- Harry Allen Generating Station – Nevada Power: 628 MW of total peak summer capacity located 24 miles northeast of Las Vegas, Nevada. The Harry Allen Generating Station is comprised of the 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 – Nevada Power: 272 MW Summer capacity located in North Las Vegas, Nevada. Formerly Las Vegas Cogen, the Las Vegas Generating Station is

comprised of one (1x1) natural gas-fired aero derivative combined cycle rated at 48 MW, and two (2x1) natural gas-fired aero-derivative combined cycle units rated at 112 MW each.

- Navajo Generating Station – Nevada Power: Nevada Power has undivided ownership rights to 255 MW of net capacity, which reflects an 11.3 percent ownership share of the Navajo Generating 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 Navajo Project includes the generating station, transmission lines and interconnections, water, and rail facilities, and is co-owned by five parties as tenants-in-common ("Co-Tenants"), who together with the United States are "Participants" in the Navajo Project. The Participants' relative interests in the non-transmission facilities is as follows:

    - Salt River Project ("SRP") (42.9%);
    - U.S. Bureau of Reclamation (24.3%), whose share is owned by the SRP;
    - Arizona Public Service (14%);
    - Nevada Power (11.3%); and
    - Tucson Electric Power (7.5%)

  SRP serves as the operator. Los Angeles Department of Water and Power ("LADWP") has an ownership share in the transmission facilities and has decommissioning responsibilities associated with its former interest in the generating facility.

- Nellis Solar PV II - Nevada Power: 15 MW AC capacity, located on the Nellis Air Force Base in North Las Vegas, Nevada. The Nellis PV plant is a single axis tracker, consisting of 10 1.5 MW blocks. The plant went into service in November of 2015.

- North Valmy Station - Sierra: Sierra owns 50 percent of two coal-fired condensing steam units with a peak summer capacity of 522 MW. Sierra's share of capacity from the two units at Valmy is 261 MW. North Valmy Station is located 19 miles west of Battle Mountain, Nevada.

- Silverhawk Generating Station – Nevada Power: 520 MW of total peak summer capacity, including duct burners, located approximately 26 miles northeast of Las Vegas, Nevada. The plant is comprised of one 2x1 natural gas-fired combined cycle unit.

- Sun Peak Generating Station – Nevada Power: 210 MW of net summer peak capacity located in Las Vegas, Nevada. Sun Peak Generating Station is comprised of three dual fuel (natural gas and No. 2 fuel oil) simple-cycle combustion turbine units (each capable of producing 70 MW).

- Tracy Station - Sierra: 753 MW of total peak summer capacity, located approximately 15 miles east of Reno, Nevada. The Tracy Station is comprised of one natural gas-fired

steam unit with a total peak summer capacity of 108 MW, and two natural gas- fired combined cycle blocks with a peak summer capacity of 645 MW.

- Walter Higgins Generating Station - Nevada Power: 530 MW of total peak summer capacity including duct burners, located approximately 35 miles southwest of Las Vegas, composed of one 2x1 natural gas-fired combined cycle unit.

Figure GEN-1 summarizes in tabular form Nevada Power's and Sierra's generating units and their respective operating characteristics including: name plate ratings, and winter, summer and peak capacities, commercial operation dates, deprecation-based retirement dates and fuel types.

FIGURE GEN-1
GENERATING UNITS SUMMARY

Unit	Commercial Operation Date	Depreciation Based Retirement Date	Prime Mover[2]	Designation	Name Plate (MW)	Winter Capacity (MW)	Summer Capacity (MW)	Fuel Type	Primary Fuel Storage Capacity[3]	Secondary Fuel Storage Capacity
Sierra[4]										
Clark Mt. 3	1994	*2024*	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Clark Mt. 4	1994	*2024*	CT	Peaker	73	72	66	Nat Gas /Diesel	0	3.5 days
Ft. Churchill 1	1968	*2025*	Steam	Intermediate	105	113	113	Nat Gas	0	0
Ft. Churchill 2	1971	*2028*	Steam	Intermediate	105	113	113	Nat Gas	0	0
Tracy 3	1974	*2028*	Steam	Intermediate	110	108	108	Nat Gas	0	0
Tracy 4&5 (Pinon)	1996	*2031*	CC /Steam	Intermediate	113	108	104	Nat Gas	0	0
Tracy 8, 9, 10	2008	*2043*	CC /Steam	Base	623	578	553	Nat Gas	0	0
Valmy 1	1981	*2025*	Steam	Intermediate	127	127	127	Coal	200 days	200 days
Valmy 2[5]	1985	*2025*	Steam	Intermediate	134	134	134	Coal	200 days	200 days
Nevada Power										
Clark 4	1973	2020	CT	Peaker	60	63	55	Nat Gas	0	0
Clark 5, 6, 7	1979. 1979, 1994	2034	CC /Steam	Intermediate	236	84	73	Nat Gas	0	0
Clark 7, 8, 9	1980, 1982, 1994	2033	CC /Steam	Intermediate	236	84	73	Nat Gas	0	0
Clark 11 - 22	2008	*2038*	CT	Peaker	726	57	52	Nat Gas	0	0
Goodsprings	2010	2040		Base	7.5			Waste Heat	0	0
Harry Allen 3	1995	2025	GT	Peaker	72	84	74	Nat Gas	0	0
Harry Allen 4	2006	2036	GT	Peaker	72	84	74	Nat Gas	0	0
Harry Allen CC	2011	2046	CC /Steam	Base	558	524	510	Nat Gas	0	0
Chuck Lenzie 1	2006	*2041*	CC /Steam	Intermediate	610	601	585	Nat Gas	0	0
Chuck Lenzie 2	2006	*2041*	CC /Steam	Intermediate	610	601	585	Nat Gas	0	0
Silverhawk CC	2004	*2039*	CC /Steam	Intermediate	599	599	560	Nat Gas	0	0
Walt Higgins CC	2004	*2039*	CC /Steam	Intermediate	688	600	550	Nat Gas	0	0
Navajo 1, 2, 3[6]	1974	*2019*	Steam	Base	255	255	255	Coal	180 Days	180 Days
LV Gen 1	1994	*2029*	CC /Steam	Intermediate	61.3	51	48	Nat Gas	0	0
LV Gen 2	2004	*2039*	CC /Steam	Intermediate	148.8	115	112	Nat Gas	0	0
LV Gen 3	2004	*2039*	CC /Steam	Intermediate	148.8	115	112	Nat Gas	0	0
Sun Peak 3	1991	*2026*	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 4	1991	*2026*	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	0
Sun Peak 5	1991	*2026*	CT	Peaker	98.1	74	72	Nat Gas /Diesel	0	180 hours[7]

2 "CT" indicates combustion turbine, "CC" indicates combined cycle.
3 Fuel Storage Capacity Assumes Full Load Operation.
4 Brunswick is not listed because it is a Black Start Only unit and is not available for capacity.
5 The two Valmy units are 50% owned by Idaho Power Company. Figure GEN-1 shows only Sierra's 50% share of the capacity of the two Valmy units.
6 Navajo Generating Station is a 2,250 MW Station. Nevada Power owns 11.5 percent interest in Navajo. Table GEN-1 only shows Nevada Power's 11.5 percent share of the capacity of Navajo.
7 No Diesel fuel is currently stored on site

2. OTHER GENERATION ASSETS

Nevada Power and Sierra hold ownership interests in three other generation assets:

- Brunswick Diesel Plant - Sierra: The Brunswick Diesel Plant is a six MW Emergency "Black Start Only" plant, comprised of three reciprocating diesel fired engines located on approximately 10 acres in Carson City, Nevada. This Plant is operational; however, since it is black start only, it cannot be used to serve customer load and so does not provide system capacity.

- Mohave Generating Station – Nevada Power: The Mohave site is located in Laughlin, Nevada and is the previous site of a 1,500 MW coal-fired generating plant. The site is co-owned by Southern California Edison ("SCE") (56%), SRP (20%), Nevada Power (14%) and LADWP (10%). SCE is the controlling partner of the facility. Mohave ceased operations January 1, 2006 and has been decommissioned.[8] In 2015, the co-owners agreed to proceed with selling the majority of the property through a public sale process. The property was listed by a nationwide commercial real estate firm in October 2016. No sales transactions have been executed at this time.

- Reid Gardner Generating Station – Nevada Power: The last unit at the Reid Gardner Generating Station ceased operations in March 2017 and the plant is in a state of Post-Operational Reserve.[9] The units are currently being dismantled. Dismantling and demolishing will be completed over the next 18 months and site remediation will follow. Nevada Power is continuing with the decommissioning and demolition plan approved by the Commission in Docket 15-05004. A final disposition plan for the site will be developed as the site remediation scope becomes better known.

3. RETIREMENT DATES

In Docket No. 08-08002, Nevada Power proposed and the Commission approved the Life Span Analysis Process ("LSAP") to determine and reevaluate the economic useful lives of the Companies' generating units. Since that proceeding, both the Companies and the Commission have come to rely on this process, rather than general rate case reviews through which rates of deprecation are set, for determining the appropriate depreciation planning retirement dates to be used for generating units.

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8 As defined in NRS § 704.7332.

9 As defined in NRS § 704.7335.

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. For generating facility that have joined the Companies' fleet since the adoption of the LSAP, a unit's initial life span is established when the unit is first put in service. In the case of older units with in service dates preceding the Commission's approval of the LSAP, the Reassessment Protocol set forth in the LSAP was used to set an initial life.

After a unit is commissioned and has been in operation, its life span may be reassessed to ensure that the Initial Life Span Assessment is still valid, or to determine a new plan that is more appropriate for the unit. The reassessment of unit life span can be undertaken for any of the following Reassessment Criteria:

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Change in Environmental Compliance Requirements
- Change in Infrastructure
- Significant Event
- Commission-Ordered Reassessment.

When a reassessment is undertaken, it can range from cursory to detailed, depending on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the Initial Life Span Assessment. At the other end of the spectrum, a unit entering its planned last decade of operations may implicate operations, maintenance, environmental and infrastructure issues, could dictate a detailed review to assess the unit's remaining life span. No matter the nature of the review, the key steps of the Reassessment Protocol are as follows:

- Unit Assessment
- Environmental Assessment
- Infrastructure Assessment
- Development of Options
- Options Input to Resource Planning and Financial Analysis
- Final Decision on Life Span Assessment and Implementation Plan

a. 2018 LSAPS AND RETIREMENT DATE CHANGES

During 2018, fourteen units will trigger the Reassessment Criterion of entering into the Last Decade of Life Span. New LSAPs have not been prepared for Sierra's North Valmy Units 1 and 2 or for Nevada Power's Navajo Units 1, 2 and 3. These facilities are subject to unique requirements, which are described below. LSAPs have been prepared for remaining units subject to the Last Decade of Life Span, which are listed below, and discussed further in this section.

- Nevada Power's Clark Unit 4 – which is scheduled to retire in 2020.
- Sierra's Clark Mountain 3 & 4 – which are scheduled to retire in 2024.

- Sierra's Fort Churchill 1 – which is scheduled to retire in 2025.
- Nevada Power's Harry Allen Unit 3 – which has a 2025 retirement date.
- Nevada Power's Sun Peak Units 3, 4, 5 – which are scheduled to retire in 2026.
- Sierra's Tracy Unit 3 – which has a 2028 scheduled retirement date.

Updated LSAP reports for the remaining units are included in the Technical Appendix GEN-4. The recommendations for the remaining generating units subject to LSAP review in this proceeding are summarized in Figure Gen-2 below:

FIGURE GEN-2
LSAP RESULTS FOR ALL OTHER GENERATING UNITS

Unit	Currently Approved Depreciation Retirement Date	LSAP Recommended Date	Additional Years of Continued Operation	Unit Age at Retirement
Clark Unit 4	2020	2030	10	57
Clark Mountain Unit 3	2024	2034	10	40
Clark Mountain Unit 4	2024	2034	10	40
Fort Churchill Unit 1	2025	2028	3	60
Harry Allen Unit 3	2025	2035	10	40
Sun Peak Unit 3	2026	2031	5	35
Sun Peak Unit 4	2026	2031	5	35
Sun Peak Unit 5	2026	2031	5	35

The current Action Plan is impacted by the change in the retirement date of Clark Unit 4. As noted in the LSAP report for this facility, Clark Unit 4 is in an operational condition that will allow it to continue to meet its operational in support of customers and the electric system. However, due to its age, if Clark Unit 4 was to experience a major failure or become subject to any new emissions standard, the Companies would immediately assess if retirement was appropriate.

The continued operation of all of these units were analyzed through the Commission-approved LSAP. With no known environmental regulations that would require significant capital upgrades and no other triggering events impacting the retirement decision for these units, the Companies are recommending continuing operation of these units through and beyond their original retirement dates. The units will continue to require other operational capital and maintenance expenses to maintain reliable capacity factors. Moreover, these units will continue to be reassessed or, in the case of another triggering event, reviewed immediately to determine the appropriateness of the

existing retirement dates. These reviews will be included in a future IRP or IRP amendment in the form of new or revised LSAPs.

b. Navajo Units 1-3

The planned retirement of the Navajo Generating Station in 2019 was approved by the Commission in Nevada Power's 3rd Amendment to the Emissions Reduction and Capacity Replacement ("ERCR") Plan, Docket No. 17-11005, which was filed on November 6, 2017. The Companies are not proposing to make any changes to the December 31, 2019 retirement date for Navajo Units 1-3.

c. North Valmy Unit 2

Sierra completed an LSAP for North Valmy Units 1 and 2 earlier in 2018, which was filed with the Commission on February 16, 2018 in a compliance filing associated with Docket No. 16-07001. The February 16, 2018 LSAP recommended maintaining the current Commission-approved retirement dates of 2025 for both Units 1 and 2. No action has been taken on the Valmy LSAP as of the date of the filing of this Joint IRP. The Companies are proposing to make no changes in the recommendations regarding North Valmy Unit 2 that were included in the February 16, 2018 LSAP. A discussion of the potential early retirement of North Valmy Unit 1 follows.

d. North Valmy Unit 1

The February 16, 2018 LSAP recommended maintaining the current Commission-approved retirement dates of 2025 for both Units 1 and 2. In this Joint IRP filing, which benefits from the context of the gigawatt of renewable resources that Companies are proposing to add to their portfolios, the Companies are proposing the retirement of North Valmy Unit 1 on December 31, 2021. The reasoning supporting this proposal, as well as the conditions under which the Companies are proposing to advance the retirement of North Valmy Unit 1 are set forth below.

First and foremost, the early retirement of North Valmy Unit 1 is conditioned on the rejection of Ballot Question 3. If Ballot Question 3 fails to pass in November, 2018, the Companies will continue to perform long-term planning for customers, and will be in a position to add resources to displace the energy and capacity currently provided by North Valmy Unit 1 (*i.e.*, the gigawatt of renewable energy and 100 MW of battery storage contained in the Low Carbon Case and the Renewable Case). The early retirement of North Valmy Unit 1 is conceivable only if the Companies are charged with and capable of managing and planning for energy resources beyond 2023.

As is discussed in more detail below, from the four long-term planning cases designed and analyzed for this filing, the Companies selected the Low Carbon Case as the Preferred Plan and the Renewable Case as the Alternative Plan. The Renewable Case and the Low Carbon Case are

similar in most respects: both cases include the largest investment in renewable energy of any integrated resource plan filed by NV Energy. Both cases include the addition of three clean energy projects located in northern Nevada: a 100 megawatt (MW)[10] solar facility in Washoe County, with a 25 MW/100 MWh battery energy storage system, a 200 MW solar facility in Washoe County with a 50 MW/200 MWh battery energy storage system, and a 101 MW solar facility in Humboldt County with a 25 MW/100 MWh battery energy storage system. Both cases include the addition of three clean energy projects in southern Nevada: a 300 MW solar facility, a 250 MW solar facility, and a 50 MW solar facility, all located in Clark County. As discussed in more detail in the Economic Impacts portion of the Economic Analysis, these six projects, with 1,001 MW of solar generation and 100 MW of battery energy storage will directly pump more than $2.175 billion of capital investment into Nevada's clean energy economy, allow Nevada Power and Sierra to meet the pace of economic growth in both northern and southern Nevada, and keep rates low. Simply put, both cases advance Nevada's energy policy objective of maximizing Nevada's abundant resource – the sun – to meet the State's electricity needs.

The primary difference between the Alternative and Preferred Plans is that the Low Carbon Case retires North Valmy Unit 1 at the end of 2021, ahead of the current schedule of 2025. The decision to retire North Valmy Unit 1 early is plainly a policy decision, not one based exclusively on economics. The present worth of revenue requirement ("PWRR") of the Low Carbon Case, which features the early retirement of North Valmy Unit 1, is less than two-tenths of a percent higher than the PWRR of the Renewable Case. In the five-year analysis, the Renewable Case is $11 million more cost effective than the Low Carbon Case, on a base of approximately $5.68 billion. As shown in Figure GEN-3 below both cases have lower fuel and purchased power costs in the 20-year and 30-year outlook, than the All Market Case in which only 300 MW of solar generation is added.

FIGURE GEN-3
BASE LOAD, BASE FUEL, MID-CARBON ECONOMIC ANALYSIS

	5 Year PWRR Increase vs Least Cost (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
All Market	$ 1	$ 57	$ 135	$ 177
Renewable	$ -	$ -	$ -	$ -
Low Carbon	$ 11	$ 22	$ 22	$ 22
Development	$ 32	$ 74	$ 75	$ 51

10 All MW values are nameplate ratings measured as alternating current ("ac").

Because the overall impact to customers of the Low Carbon and the Renewable Cases falls within two-tenths of a percent of one another, the Companies carefully evaluated two other metrics in order to select the Preferred Plan: the economic impact of each plan to the State of Nevada and the impact of the plans on the environment.

A qualitative assessment of the economic impact of the Renewable Case and the Low Carbon Case shows little difference, at least in the near-term, between the two plans. Both present the same near-term investment by developers in solar PV generation, battery energy storage systems, and developer-funded generation interconnections, as well as investments by NV Energy in transmission system network upgrades. With respect to the impact on the environment, the Low Carbon Case retires coal-fired generation, reducing the impact of NV Energy's operations on the environment. NV Energy's selection of the Low Carbon Case as the Preferred Plan was made based on the closeness of the fit, so to speak, between the two cases and the values of our customers, Nevada's energy policy and NV Energy's overall corporate strategy.

Overall, the goal of transforming its generation fleet by doubling its renewable resource portfolio by 2023 and aspiring to ultimately deliver 100 percent renewable energy to customers, while at the same time continuing to deliver energy at prices well below the national average, are the centerpieces of NV Energy's corporate strategy. This strategy delivers what customers have told us they value and what policy makers have identified as the goals for Nevada's energy policy.

The Companies have already taken significant steps along this path, moving away from coal-fired generation with the retirement of Mojave and Reid Gardner, and exiting participation in the Navajo Generation Station no later than December 31, 2019. The Low Carbon Case is the next logical step to advance Nevada's energy policy. Since both the Renewable Case and the Low Carbon Case put additional clean renewable energy into service and reduce customers' exposure to natural gas price fluctuations, the selection of the Preferred Plan turned on the impact of the two plans on Nevadans' stated desire to preserve and protect their natural environment. The Low Carbon Case reduces NV Energy's impact on the local, national and global environment, advances the goal of reducing CO2 emissions per unit of energy delivered, and moves the Companies ever closer to their aspirational goal. This is why we selected the Low Carbon Case as the Preferred Plan: it delivers what customers have requested and value, it mitigates risk, it is low cost and it provides flexibility to meet Nevada's energy needs in a cost-effective and sustainable manner.

This decision has not been made lightly, however. North Valmy Unit 1 is a critical supply resource, securing the reliability of the northern system generally, and enabling NV Energy to serve load to most of Nevada's mining industry located in the Carlin Trend and the commercial and industrial load located east of Reno. After all, another critical element of NV Energy's mission and obligation is to deliver the safe and reliable energy services upon which our customers and Nevada's economy

depend. Thus certain additional conditions must be satisfied in order to achieve the early retirement of North Valmy Unit 1.

First, the PPAs for the output of the three new northern Nevada renewable energy projects and stationary storage projects included in Low Carbon Case must be approved by the Commission and then must demonstrate sufficient development progress to ensure commercial operation before June 2022. The resources secured by these three PPAs are listed below:

FIGURE GEN-4
EARLY RETIREMENT OF VALMY 1:
SIERRA PPAS THAT MUST BE APPROVED

Project	PV Nameplate Capacity	Storage Capacity	Resource Planning Capacity
NextEra	200 MW	50	117
NextEra	100 MW	25	58
Cypress Creek	101 MW	25	59
Total	**401 MW**	**100**	**234**

Second, NV Energy must have adequate capacity to serve customer load. Third, conditions in the western energy markets must be such that NV Energy has sufficient access to economic energy and capacity to mitigate the cost pressure and reduction in flexibility associated with having power available from North Valmy Unit 1.

The first objective condition is easily measured. NV Energy's PPAs contain project milestones. NV Energy will track each of the project milestones for the output of all six solar PV facilities, including the three northern projects, as well as the project milestones for each of the stationary storage systems. The three northern Nevada projects must provide adequate assurance that it will begin commercial operations before June 2022 in order to support the retirement of North Valmy Unit 1.

Turning to the second condition, prudent, long-term resource planners use several metrics to assess reliability. To monitor and ensure that the following reliability conditions are being satisfied, NV Energy will establish a process for reviewing these criteria no fewer than two times per year. The Companies' Resource Planning group will track and provide status of conditions to the Companies' Risk Committee for their review and approval. If conditions are met then the unit would be retired early.

- Production cost modelling results produce a "loss of load probability" or LOLP metric. This metric measures the probability that system demand will exceed capacity over a given period of time. For any given hour, an increase in the LOLP by more than 100% would trigger the reevaluation of the North Valmy Unit 1 retirement.

- A second metric used by resource planners to assess the reliability attributes of a given plan is "expected unserved energy," or "emergency energy." This metric is defined as a measure of resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria.[11] Any megawatt-hour increase in expected unserved energy under the North Valmy Unit 1 retirement scenario would trigger a reevaluation of the retirement.
- Third, NV Energy will track the traditional resource planning criteria for loss of load expectation to ensure that this metric does not exceed the one day in 10 year criterion. Because real-time system reliability is paramount, additional analysis similar to that developed by the CAISO may be used by NV Energy to assess real-time reliability risk.

In addition, NV Energy will closely monitor and track volumetric and demand growth by tracking balancing authority area load against the transmission load forecast component of the 2018 IRP Forecast. Transmission area load of 2,800 MW will trigger a re-evaluation and, possibly, delay of the retirement of North Valmy Unit 1. The basis for this MW trigger are discussed in more detail in the Transmission Plan section of this narrative.

The metrics described above measure reliability directly; load growth within the constrained transmission system provides an indirect measure of reliability. Economics are a second critical element of sound long-term resources planning. Moreover, economics are critical to NV Energy's business strategy and its goal to provide another decade of affordable energy to Nevadans. While the PWRR difference between the Low Carbon and Renewable Cases are relatively small, the Companies will monitor the production cost impact of any North Valmy Unit 1 retirement on retail rates and reevaluate the retirement decision if the retirement of North Valmy Unit 1 increases Base Tariff Energy Rates by more than $0.00250 per kilowatt-hour versus the non-retirement scenario.

4. UPDATE TO PREVIOUSLY-APPROVED GENERATION PROJECTS

a. ACQUISITION OF SNWA'S SHARE OF SILVERHAWK

In Docket No. 15-07004, Nevada Power requested IRP approval to purchase the Southern Nevada Water Authority's ("SNWA's") share of the Silverhawk Generating Station. The SNWA's share of the Silverhawk Generating Station accounted for 120 MW of the facility's summer capacity. The purchase was completed on March 31, 2017. The Commission approved the acquisition costs for inclusion in rate base in Nevada Power's most recent general rate review proceeding, Docket No. 17-06003.

[11] See North American Electric Reliability Corporation: Probabilistic Assessment, Technical Guideline Document. August 2016. Accessed May 3, 2018 at https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf.

b. RETIREMENT AND DECOMMISSIONING OF TRACY UNITS 1 AND 2

In Docket No. 12-08009, Sierra recommended and the Commission approved retiring Tracy Units 1 and 2 in lieu of making investments necessary to comply with Best Available Retrofit Technology requirements under the Clean Air Act, no later than January 1, 2015. Only Units 1 and 2 have been retired, the remainder of the Tracy Plant continues to operate.

Sierra began decommissioning Tracy Units 1 and 2 in October, 2014. The following work was completed through the end of 2017:

1. Demolition of the fuel oil tanks;
2. Disconnection of the Tracy Units 1 and 2 from the Bulk Electric System;
3. Disconnection of the natural gas fuel supply;
4. Relocation of operational controls from Tracy Units 1 and 2 to separate from the rest of the Tracy Station; and
5. Preparation of detailed work packages and procedures for Tracy Units 1 and 2:
6. Decommissioning of the fire protection system;
7. Demolition of the Tracy Units 1 and 2 cooling tower;
8. Relocation of utilities;
9. Removing hazardous and combustible sources;
10. Isolating Tracy Units 1 and 2 from the rest of the Tracy facility by installing fencing.

The decommissioning of Tracy Units 1 and 2 has been completed and isolation of Units 1 and 2 from the balance of the Tracy facility is completed. Tracy Units 1 and 2 will be kept in a "cold and dark" state, in which they will not pose any risk to the reliability of the other Tracy generating units. The remaining demolition of Tracy Units 1 and 2 will take place at a future date when the remainder of the Tracy facility is decommissioned and demolished, or when demolition is necessary to support new generation or transmission needs.

In the interim, periodic inspections of the integrity of the asbestos and the stack structures will need to be conducted. This is estimated to cost approximately $150,000 per year for annual asbestos inspections and $35,000 every three years for stack structure inspections. If necessary, asbestos encapsulation and/or structural enhancement of the stacks will need to be undertaken.

c. DRY LAKE SOLAR

In Docket No. 14-05003, the Commission approved Nevada Power's request to perform initial site development activities related to a Dry Lake Solar Energy Zone ("SEZ") site located northeast of Las Vegas. In Docket No. 15-07004, the Commission approved Nevada Power's request to continue site development activities of the SEZ. In the 2018 Joint IRP, Nevada Power is not

requesting any additional funding or approvals for the SEZ, but instead provides the Commission the following update on Nevada Power's progress in developing the SEZ.

Since Nevada Power's 2015 IRP filing, the Bureau of Land Management ("BLM") completed its processing of the right of way ("ROW") applications, including environmental studies, and issued ROW N-93337 and N-93586 to Nevada Power on June 18, 2015. Subsequently, Nevada Power has received multiple extensions to the grant offers to negotiate the terms and conditions and pursue commercial opportunities for the site. In April 2017, Nevada Power amended ROW N-93586 to address the Harry Allen Generating Station pond operations[12] and on April 18, 2018, Nevada Power issued an executed offer for N-93337. The final execution of grant offer N-93337 by the BLM is imminent, and the revised draft of grant offer N-93586 is pending. Pursuant to Nevada Power's Dry Lake SEZ Large Generator Interconnection Agreement, commercial operations of the solar facility can occur soon as December 2020.

In accordance with the Commission's approval in Docket Nos. 14-05003 and 15-07004, Nevada Power has completed the following site activities in connection with seeking state and federal authorizations for the SEZ:

- Completed Environmental Assessments and Biological Assessments through the Bureau of Land Management and the U.S. Fish and Wildlife Service.
- Received Decision Records for both the 130 MW and 20 MW portions of the project on May 27, 2015, and June 9, 2015, respectively including the Finding of No New Significant Impact ("FONNSI") for the 130 MW, FONNSI for the 20 MW and associated Biological Opinions.
- Received ROW offers N-93337 (660 acres) and N-93586 (150 acres) from the BLM on June 18, 2015, for the Dry Lake Solar Energy Center up to 150 MW.
- Submitted an application package to the Commission on March 27, 2015, for a Utility Environmental Protection Act Permit to Construct ("UEPA Permit") the Dry Lake Solar Energy Center at 150 MW, along with associated electric facilities.
- Received a conditional Compliance Order from the Commission on July 27, 2015, approving the UEPA Permit to be issued upon completion and submittal of all permits and approvals necessary to construct the project.
- The LGIA with the transmission provider (NV Energy) was executed on July 26, 2016 with a commercial operations date scheduled for December 1, 2020.

[12] The original application for ROW N-93586 was for 150 acres, however, it was amended in to reduce the project area to 85 acres to better accommodate operations at the Harry Allen Generating Station. The site is still projected to be able to produce up to 20 MW of solar power.

- Requested amendment to ROW offer N-93586 in April, 2017.
- Provided a signed copy of the ROW offer N-93337 to the BLM on April 18, 2017.
- Awaiting revised offer letters on ROW grants N-93337 and N-93586 from the BLM with updated costs. Upon the BLM receiving all mitigation funds due at signing, the ROW grants will be issued.

In accordance with the Commission-approved action plans in Dockets 14-05003 and 15-07004, Nevada Power has expended approximately $2.18 million on the above activities through April 30, 2018, of which approximately $1.5 million, including administrative fees, were spent on the BLM land auction to acquire the 660 acres associated with grant offer N-93337. Nevada Power estimates a total of $78,000 dollars will be spent in 2018 to monitor tortoise activities for a total of $2.23 million dollars spent on development at the SEZ. All the expenditures to date are less than the overall Commission approved funding from Docket Nos. 14-05003 and 15-07004.

Pending full execution of the ROW grants, Nevada Power intends to complete the remaining site development activities that were previously approved in Docket 15-07004, including:

- Translocation of desert tortoise as required under the ROW grant.
- Complete environmental mitigation plans per the ROW grant.
- Completion of the geotechnical study.
- Identification and possible permitting of alternative water resources near the site.

When the ROW grants are issued, lease payments and initial mitigation costs will be due and these costs are not included in the budget estimates. However, Nevada Power recognizes that an approval to pursue the full development of the SEZ will require Commission approval, and thus the request must be submitted in a future IRP amendment. As a result and as stated above, Nevada Power is not requesting Commission approval to spend additional money in the Action Plan period (2019-2021) on the SEZ.

5. EMISSION REDUCTION AND CAPACITY REPLACEMENT ("ERCR") – GENERATION PROJECTS

Senate Bill 123 ("SB 123") (2013 Nevada Legislature) and its associated regulations required the orderly retirement or divestiture of coal fired generating assets owned by Nevada Power. Nevada Power filed its initial ERCR plan on May 1, 2014, in Docket No. 14-05003, which the Commission approved on October 28, 2014. The initial ERCR plan called for the retirement of Reid Gardner Units 1, 2 and 3 on or before December 31, 2014, Reid Gardner Unit 4 by December 31, 2017,

and divestiture or elimination[13] of Nevada Power's interest in the Navajo Generating Station by December 31, 2019. In the Company's ERCR Second Amendment, Docket No. 16-08026, the Commission approved the accelerated retirement of Reid Gardner Unit 4, from December 31, 2017 to on or about February 28, 2017. In Nevada Power's ERCR Third Amendment, Docket No. 17-11005, the Commission approved a stipulation on February 1, 2018, for the retirement of Nevada Power's share of Navajo on or before December 22, 2019.

a. DECOMMISSIONING AND DEMOLITION OF REID GARDNER STATION

Reid Gardner Units 1-3 ceased operation in December 2014 and Reid Gardner Unit 4 ceased operation in March 2017. Decommissioning of Reid Gardner Units 1-3 began in January 2015 and April 2017 for Reid Gardner 4. Nevada Power awarded a contract for demolition of Reid Gardner Units 1-4 in January 2018. The demolition contractor began work on site in February 2018. The demolition portion of the project is expected to be completed within 18 months. Site remediation and restoration work will follow the plant demolition.

b. DECOMMISSIONING AND DEMOLITION OF NAVAJO GENERATING STATION

As approved by the Commission in Docket No. 17-11005, Nevada Power continues to work with the other owners of the Navajo Generating Station in developing plans for the December 22, 2019 shutdown of the generating units and the decommissioning and demolition of the Station that will follow.

c. ERCR CAPACITY REPLACEMENT PROJECTS

In addition to mandating the retirement of Nevada Power's coal fleet, SB 123 provided for the replacement of coal-generated capacity with a combination of company-owned and purchased power contracts. In Nevada Power's original ERCR plan, Docket No. 14-05003, the Commission approved the acquisition of established generating facilities from which the Nevada Power had previously purchased power: three units at the Las Vegas Cogeneration Station (now renamed the Las Vegas Generating Station) and three units at the Sun Peak facility. The purchases of these units were completed in 2014 and their acquisition costs were approved for inclusion in Nevada Power's rate base by the Commission in Docket No. 17-06003.

Additionally in Docket No. 14-05003, the Commission approved the construction of the Nellis Solar PV II project. The project was a 15 MW (ac) PV generating facility located on the Nellis Air Force Base. Nevada Power began construction in April 2015 and the project was completed and

[13] *See,* Nev. Admin. Code § 704.90593 (defining "eliminate" and "elimination" for the purposes of the Commission's ERCR plan regulations).

went into service in November 2015. The Commission approved the final project costs for the Nellis Solar PV II project for inclusion in rate base in Docket No. 17-06003.

B. LONG-TERM PURCHASE POWER AGREEMENTS

The Companies meet the energy demand of its customers with company-owned and controlled generation (discussed above), as well as with a combination of long-term power purchase agreements ("PPAs"), and short-term energy transactions. The Companies also sell energy to third parties under long-term agreements.

The Companies meet the requirements of Nevada's renewable portfolio standard ("RPS") through a combination of company-owned generation, Commission-approved long-term PPAs with renewable energy resources, agreements for purchase of portfolio energy credits ("PCs"), and energy efficiency programs. The Companies also sell PCs under the NV GreenEnergy Rider "NGR" program to customers through renewable energy agreements.

Figure CON-1 lists all of Nevada Power's renewable and non-renewable long term PPAs, PC only and sales agreements. Figure CON-2 lists all of Sierra's renewable and non-renewable PPAs, PC only and sales agreements.

FIGURE CON-1
NEVADA POWER LONG-TERM PURCHASE POWER AGREEMENTS

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date	Anticipated Remaining Cost
Renewable Purchase Agreements					
PPAs (Commercial)					
ACE Searchlight[QF]	Solar[S]	17.5	12/16/2014	12/31/2034	$ 117,047,000
APEX Landfill[QF]	Methane	12.0	3/1/2012	12/31/2032	$ 80,248,000
Boulder Solar I[EWG]	Solar[S]	100.00	12/9/2016	12/31/2036	$ 233,562,000
Colorado River Commission-Hoover (RPS Excluded)	Hydro	237.6	10/1/2017	9/30/2067	$ 876,337,000
Desert Peak 2[QF]	Geothermal	25.0	4/17/2007	12/31/2027	$ 45,585,000
FRV Spectrum[QF]	Solar[S]	30.0	9/23/2013	12/31/2038	$ 193,736,000
Galena 2[QF]	Geothermal	13.0	5/2/2007	12/31/2027	$ 24,616,000
Jersey Valley[QF]	Geothermal	22.5	8/30/2011	12/31/2031	$ 70,645,000
McGinness Hills[QF]	Geothermal	96.0	6/20/2012	12/31/2032	$ 878,921,000
Mountain View[EWG]	Solar[S]	20.0	1/5/2014	12/31/2039	$ 149,838,000
Nevada Solar One (NPC)[QF]	Solar[T]	46.9	6/27/2007	12/31/2027	$ 150,123,000
NGP Blue Mountain[QF]	Geothermal	49.5	11/20/2009	12/31/2029	$ 248,033,000
RV Apex[QF]	Solar[S]	20.0	7/21/2012	12/31/2037	$ 157,356,000
Salt Wells[QF]	Geothermal	23.6	9/18/2009	12/31/2029	$ 83,443,000
Silver State[EWG]	Solar[F]	52.0	4/25/2012	12/31/2037	$ 364,841,000
Spring Valley[EWG]	Wind	151.8	8/16/2012	12/31/2032	$ 541,239,000
Stillwater Geothermal[1,QF]	Geothermal	47.2	10/10/2009	12/31/2029	$ 132,784,000
Stillwater PV[1,QF]	Solar[F]	22.0	3/5/2012	12/31/2029	$ 55,941,000
Switch Station 1[EWG]	Solar[S]	100.00	8/8/2017	12/31/2037	$ 296,959,000
Tonopah Crescent Dunes[EWG]	Solar[T]	110.0	11/9/2015	12/31/2040	$ 1,189,466,000
Tuscarora[QF]	Geothermal	32.0	1/11/2012	12/31/2032	$ 197,303,000
WM Renewable Energy-Lockwood[QF]	Methane	3.2	4/1/2012	12/31/2032	$ 31,803,000
		1231.8			
PC Purchase Agreements					
NPC-SPPC	Geothermal	2.3	10/30/2009	12/31/2028	$ 5,397,000
Nellis I (Solar Star)	Solar	13.2	12/15/2007	12/31/2027	$ 59,750,000
SunPower (LVVWD)	Solar	3.0	4/20/2006	12/31/2026	$ 8,744,000
		18.5			
PPAs (Pre-Commercial)[2]					
Techren I[EWG]	Solar[S]	100.0	1/1/2019	12/31/2043	$ 299,153,000
Techren III[QF]	Solar[S]	25.0	9/1/2020	12/31/2045	$ 57,021,000
		125.00			
Non-Renewable Purchase Agreements					
Nevada Cogeneration Associates #1[QF]	Natural Gas	85.0	6/18/1992	4/30/2023	$ 306,906,000
Nevada Cogeneration Associates #2[QF]	Natural Gas	85.0	2/1/1993	4/30/2023	$ 232,225,000
Saguaro Power Company[QF]	Natural Gas	90.0	10/17/1991	4/30/2022	$ 201,865,000
		260.0			
Renewable and Non-Renewable Sales Agreements					
City of Las Vegas NGR (Boulder Solar I)	NGR Agreement (Sale of PCs)	See Note 3	12/9/2016	12/31/2019	-
Switch NGR (Switch Station 1)	NGR Agreement (Sale of PCs)	100.0	8/8/2017	12/31/2037	-
Notes:					
1. The geothermal and solar facilities are combined into one PPA.					
2. Facilities are either under development or construction (the dates shown are expected dates).					
3. NPC shall sell 43,200 kPCs for three years .					
QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt					

FIGURE CON-2
SIERRA'S LONG-TERM PURCHASE POWER AGREEMENTS

Contract Name	Contract Type	Capacity (MW)	Commercial Operation Date	Termination Date	Anticipated Remaining Cost
Renewable Energy					
PPAs (Commercial)					
Beowawe[QF]	Geothermal	17.7	4/21/2006	12/31/2025	$ 47,186,000
Boulder Solar II[EWG]	Solar[S]	50.0	1/27/2017	12/31/2037	$ 137,754,000
Brady[QF]	Geothermal	24.0	7/30/1992	7/29/2022	$ 16,295,000
Burdette[QF]	Geothermal	26.0	2/28/2006	12/31/2026	$ 71,379,000
Galena 3[QF]	Geothermal	26.5	2/21/2008	12/31/2028	$ 99,698,000
Hooper[1,QF]	Hydro	0.75	6/23/2016	12/31/2040	$ 1,374,000
Kingston[1]	Hydro	0.175	9/19/2011	12/31/2040	$ 256,000
Mill Creek[1]	Hydro	0.037	9/1/2011	12/31/2040	$ 5,000
Nevada Solar One (SPPC)[QF]	Solar[T]	22.1	6/27/2007	12/31/2027	$ 70,613,000
RO Ranch[1,2]	Hydro	0	3/15/2011	12/31/2040	$ -
Soda Lake II[QF]	Geothermal	19.5	8/4/1991	8/4/2021	$ 6,537,000
Steamboat 2[QF]	Geothermal	13.4	12/13/1992	12/12/2022	$ 19,838,000
Steamboat 3[QF]	Geothermal	13.4	12/19/1992	12/18/2022	$ 21,454,000
Switch Station 2 (SPPC)[EWG]	Solar[S]	79.0	10/11/2017	12/31/2037	$ 209,459,000
TCID New Lahontan[QF]	Hydro	4.0	6/12/1989	6/11/2039	$ 8,569,000
TMWA Fleish	Hydro	2.4	5/16/2008	6/1/2028	$ 7,580,000
TMWA Verdi	Hydro	2.4	5/15/2009	6/1/2029	$ 7,461,000
TMWA Washoe	Hydro	2.5	7/25/2008	6/1/2028	$ 5,319,000
USG San Emidio[QF]	Geothermal	11.75	5/25/2012	12/31/2037	$ 146,676,000
		315.6			
Leased Units					
Fort Churchill Solar	Solar[S]	19.5	8/5/2015	8/4/2040	$ 69,000,000
PC Purchase Agreement					
TMWRF	Methane	0.8	9/9/2005	12/12/2024	$ 230,000
PPAs (Pre-Commercial)[3]					
Techren II[EWG]	Solar[S]	200.0	7/1/2019	12/31/2044	$ 567,165,000
Techren IV[QF]	Solar[S]	25.0	9/1/2020	12/31/2045	$ 57,009,000
Turquoise	Solar[F]	50.0	11/1/2020	12/31/2045	$ 107,487,000
		275.00			
Non-Renewable Purchase Agreements					
Newmont Nevada Energy Investment	Coal	179.0	6/1/2008	5/31/2023	$ 40,815,000
Liberty (CalPeco) EBSA	Diesel	12.0	1/1/2011	12/31/2031	$ 17,232,000
		191.0			
Renewable & Non-Renewable Sales Agreements					
Liberty (CalPeco)	Full Requirements (Capacity/Energy/PCs)	See Note 4	1/1/2016	4/30/2019	-
NPC-SPPC	Sale of PCs (Geothermal)	2.3	10/30/2009	12/31/2028	-
Apple NGR (Fort Churchill Solar)	NGR Agreement (Sale of PCs)	19.5	8/5/2015	8/4/2040	-
Apple NGR (Boulder Solar II)	NGR Agreement (Sale of PCs)	50.0	1/27/2017	12/31/2037	-
Switch NGR-SPPC (Switch Station 2)	NGR Agreement (Sale of PCs)	79.0	10/11/2017	12/31/2037	-
Apple NGR (Techren II)[3]	NGR Agreement (Sale of PCs)	200.0	7/1/2019	12/31/2044	-
Apple NGR (Turquoise)[3]	NGR Agreement (Sale of PCs)	50.0	11/1/2020	12/31/2045	-

Notes:
1. The illustrative termination date shown is subject to certain conditions, which may result in termination before or after December 31, 2040.
2. RO Ranch Hydro facility is shut down indefinitely (the PPA is still active).
3. Facilities are either under development or construction (the dates shown are expected dates).
4. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December).

QF=Qualifying Facility, EWG=Exempt Wholesale Generator, S=Single Axis Tracking, T=Solar Thermal (Tracking), F=Fixed Tilt

1. RENEWABLE PPAs

Nevada Power has executed 24 long-term renewable PPAs representing a total nameplate capacity of approximately 1,357 MW (*see,* Figure CON-1 above). The latest commercial addition to the portfolio is the Switch Station 2 solar project, which achieved commercial operation in October 2017.[14] The Techren Solar I (100 MW) and the Techren Solar III (25 MW) projects are expected to achieve commercial operation in January 2019 and September 2020, respectively. Nevada Power has executed three long-term PC-only purchase agreements representing a total nameplate capacity of approximately 18 MW. Nevada Power's renewable PPAs secure a renewable energy portfolio that is made up of a mix of solar, geothermal, hydro, methane, and wind resources.

Sierra has executed 23 long-term renewable PPAs representing a total nameplate capacity of approximately 609 MW (*see*, Figure CON-2 above). The latest commercial addition to the portfolio is the Switch Station 2 project, which achieved commercial operation in October 2017. The Techren Solar II (200 MW), Techren Solar IV (25 MW), and Turquoise Solar (50 MW) projects are expected to achieve commercial operation in July 2019, September 2020 and November 2020, respectively. Sierra has executed one long-term PC-only purchase agreement representing a nameplate capacity of 0.8 MW. Sierra's renewable PPAs secure a renewable energy portfolio that is made up of a mix of solar, geothermal, and hydro resources.

Additional information regarding both Nevada Power's and Sierra's portfolio of renewable energy PPAs is set forth below in Section 2.D.

2. NON-RENEWABLE PPAs

Figures CON-1 and CON-2 (above) also list non-renewable PPAs at Nevada Power and Sierra.

Nevada Power has executed three long-term PPAs for non-renewable generation, representing a total capacity of approximately 260 MW. These agreements are for the must-take output of the NCA 1, NCA 2, and Saguaro gas-fueled co-generation facilities.

Sierra has executed two long-term non-renewable PPAs. The first is with Newmont, pursuant to which Sierra purchases 179 MW of dispatchable output from Newmont Mining's coal-fueled facility in northern Nevada. This agreement expires on May 31, 2023. A second PPA is with

[14] Originally, Nevada Power's share of the output from the Switch Station 2 solar project was 27.2 MW and Sierra's share was 51.3 MW. Pursuant to the Switch Station 2 PPAs between Playa Solar 1 and Nevada Power, and Playa Solar 1 and Sierra, Switch Ltd., who purchases the PCs generated from the facility, could request that the energy supply and corresponding PC percentages between the north and south be reallocated. On January 17, 2018, Switch requested that 100 percent of Switch Station 2 solar project's output be allocated to Sierra. On April, 17, 2018, Sierra and Playa Solar 1 executed an amendment to this effect. On the same date, Nevada Power and Playa Solar 1 executed an amendment that suspended the PPA, until such time Switch made another reallocation request. As a result, Nevada Power currently does not receive any energy or PCs from Switch Station 2 solar project.

Liberty Utilities ("Liberty"), pursuant to which Sierra purchases 12 MW of capacity from Liberty's Kings Beach diesel units for emergency purposes. This agreement expires December 31, 2031.

3. RENEWABLE AND NON-RENEWABLE SALES AGREEMENTS

Also listed on Figures CON-1 and CON-2 are long-term renewable and non-renewable sales agreements, pursuant to Nevada Power and Sierra sell either energy, PCs, or both energy and PCs to third parties.

Nevada Power has executed three NGR Agreements pursuant to which it sells PCs to the City of Las Vegas (associated with a portion of the Boulder Solar 1 project output), and Switch Ltd. (associated with the full output of the Switch Station 1 project).

Sierra has executed a full requirements agreement with Liberty pursuant to which Sierra sells capacity, energy, and certain PCs to meet the needs of Liberty retail customers in California. The current monthly contract demand ranges from approximately 70 MW (June) to 140 MW (December). The term of the agreement is January 1, 2016 through April 30, 2019.

Sierra has executed four NGR Agreements for the sale of PCs only to Apple (associated with the full output of the Ft. Churchill Solar Array, Boulder Solar II project, Techren Solar II project, and the Turquoise Solar project, respectively) and Switch Ltd. (associated with the output of the Switch Station 2 project). Sierra has also executed one long-term agreement for the sale of PCs to Nevada Power. This PC only sale agreement expires December 31, 2028.

C. FUEL SUPPLY

1. CURRENT PHYSICAL GAS SUPPLY

A substantial portion of the Companies' current generation portfolio is fueled with natural gas. In addition, Sierra serves natural gas to retail customers in the greater Reno and Sparks areas in Northern Nevada. While they are served from different pipeline systems, both Nevada Power and Sierra are well positioned with firm transportation rights to take advantage of the dominant natural gas supply basins serving the Pacific Northwest and Southwest. These gas supply basins are the Rocky Mountain Basin, the San Juan Basin, British Columbia, Western Canada Sedimentary Basins, as well as California gas supply. The gas transport facilities that are available to move gas from these supply basins to Nevada Power's and Sierra's respective service territories are shown below in Figures GAS-1 and GAS-2.

Nevada Power takes delivery of natural gas from the Kern River pipeline system ("Kern River"), which is connected with several major gas producing regions including the Permian, San Juan, and the Rocky Mountain supply basins, as well as to California gas supply. The largest gas producing region with the best connectivity into and through Nevada Power's control area is the Rocky Mountain supply basin.

Sierra takes direct delivery of natural gas from the Paiute pipeline and the Tuscarora pipeline. Paiute receives gas supplies upstream from the Williams Gas Pipelines – Northwest system, which sources its gas supplies from British Columbia, the San Juan Basin, and the Rocky Mountain region of Wyoming, Utah and Colorado. Tuscarora receives gas supplies from GTN, near Malin, Oregon, which is connected to the gas producing regions of Western Canada Sedimentary Basin Alberta through the TransCanada pipeline system. The gas supply source for Malin gas is predominantly in the Province of Alberta, Canada.

FIGURE GAS-1
NEVADA POWER PIPELINE ROUTES

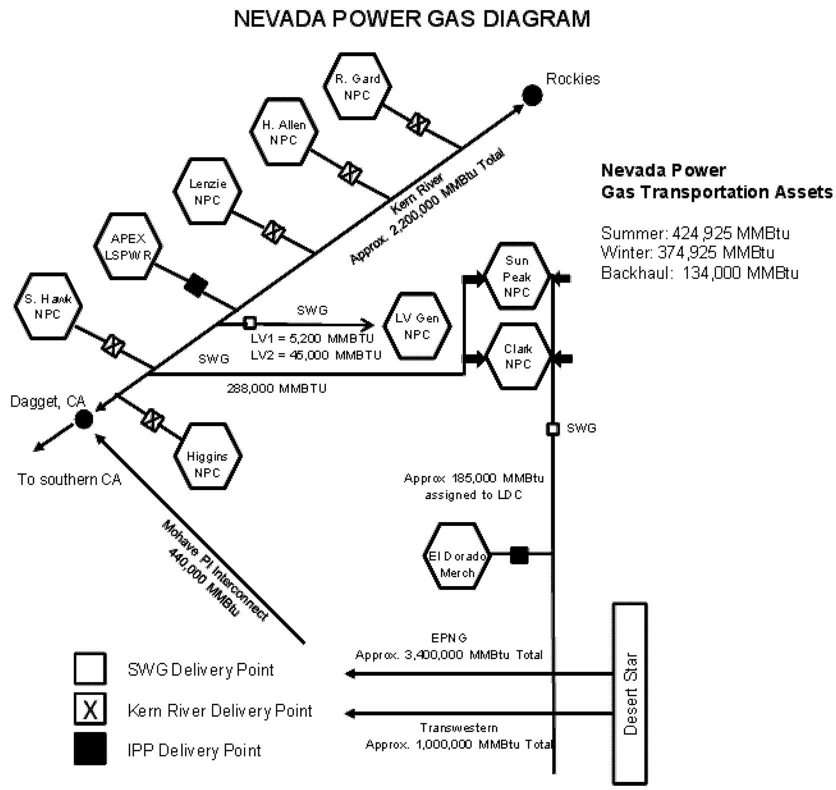

FIGURE GAS-2
SIERRA PIPELINE ROUTES

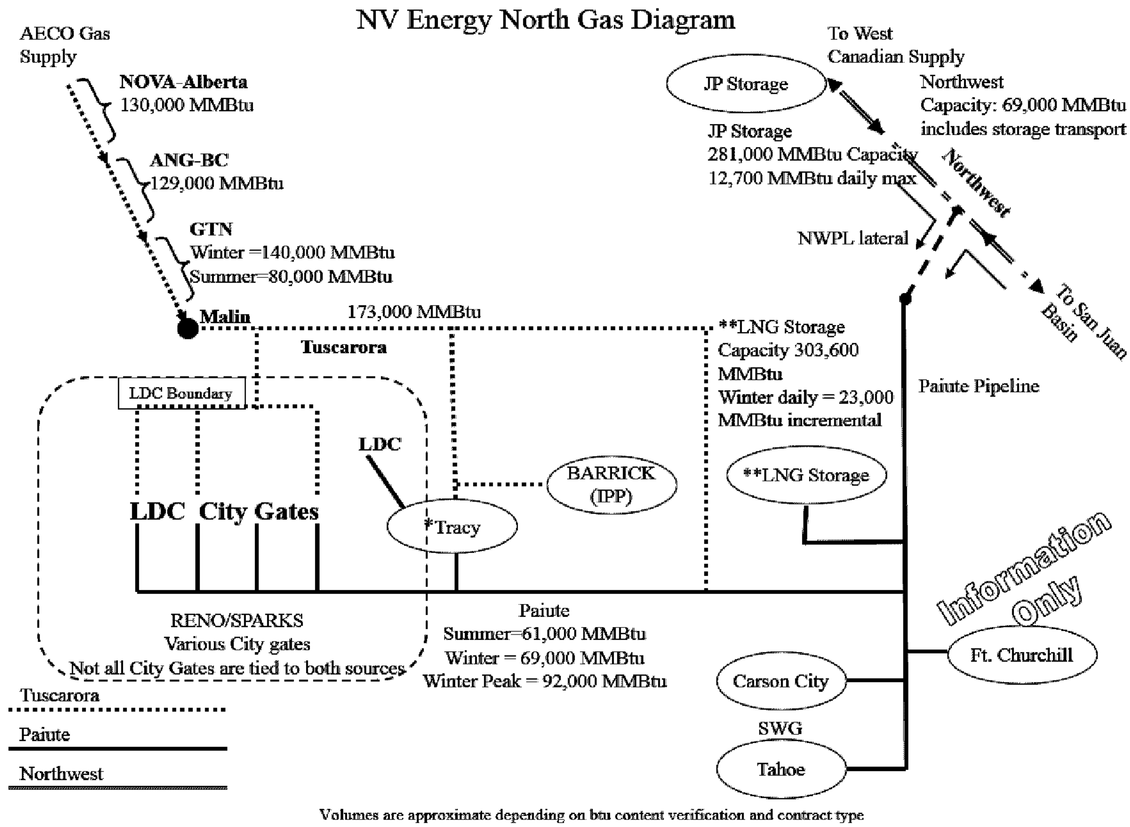

Figure GAS-3 lists Nevada Power's existing gas transportation service agreements.

FIGURE GAS-3
NATURAL GAS TRANSPORTATION CONTRACTS
(NEVADA POWER)

Contract Type	Counterparty	Contract #	Termination Date (as of 04/19/2018)	Maximum Daily Quantity (MMBTUs) Annual	Winter	Summer	Comments
TSA	Kern River	20027	4/30/2028	75,000			
TSA	Kern River	20028	4/30/2028			50,000	
TSA	Kern River	20023	4/30/2032	12,500			
TSA	Kern River	20013	9/30/2031	11,075			
TSA	Kern River	20012	9/30/2031	10,350			
TSA	Kern River	1830	9/30/2031	266,000			Forward Haul
TSA	Kern River	1617	9/30/2031	134,000			Backhaul
Rental	Kern River	Higgins Facility Charge	12/31/2039				No Volume
TSA	SW Gas	21016	4/30/2027	288,000			
TSA	SW Gas	21011	Month to Month			5,200	
TSA	SW Gas	21088	7/31/2022	45,000			

Nevada Power currently holds year-round contracts for firm forward haul gas transportation rights on Kern River totaling 374,925 MMBtu/day, with an additional 50,000 MMBtu/day in the summer that increases the maximum daily quantity to 424,925 MMBtu/day from April through October to serve a majority of its overall daily natural gas needs. Nevada Power holds rollover rights under the Kern River tariff, provided Nevada Power is willing to continue under the terms and conditions specified therein. In addition, Nevada Power has a long-term agreement with Kern River for back haul capacity of 134,000 MMBtu/day. Nevada Power may procure Topock-sourced gas for redelivery into Kern River at Daggett, California.

Gas supplies for Nevada Power's Harry Allen, Chuck Lenzie, Higgins and Silverhawk plants are delivered directly by Kern River. The gas-fired units at Edward W. Clark Generating Station and Sun Peak Generating Station receive gas delivered under a 288,000 MMBtu/day transportation service agreement with Southwest Gas Corporation ("Southwest"). The transportation agreement with Southwest provides for receipt of Kern River supplies, as well as limited quantities of gas from sellers off of the El Paso Natural Gas transmission system ("El Paso") and/or Transwestern Pipeline system ("Transwestern") south of Las Vegas. This source is available to Nevada Power only if Southwest is not using its capacity rights to serve its own requirements. As part of the acquisition of LV Cogen Unit 1 and 2 in 2015 (discussed above), Nevada Power retained the original owner's gas transportation service agreements with Southwest (LV Cogen Unit 1 45,000 MMBtu/day and LV Cogen 2 5,200 MMBtu/day).

In the Energy Supply Plan ("ESP") portion of this filing Nevada Power is seeking approval to maintain its current natural gas transportation portfolio. Nevada Power's daily gas usage requirements during July and August exceed the current contracted capacity with Kern River.

Nevada Power has adequately closed prior firm gas transportation open positions by purchasing delivered natural gas, and proposes to continue this strategy. Nevada Power will continue to evaluate the need to acquire new firm transportation capacity and may revisit this strategy in a future filing.

Figure GAS-4 lists Sierra's existing gas transportation service agreements.

FIGURE GAS-4
SIERRA'S NATURAL GAS TRANSPORTATION CONTRACTS

Contract Type	Counterparty	Contract #	Termination Date (as of 04/19/2018)	Units	Maximum Daily Quantity Annual	Winter	Summer
TSA							
	Transcanada - Alberta System						
		2010-447962	10/31/2019	GJ/Day	18,583		
		2010-447963	10/31/2019	GJ/Day	92,918		
		2010-447964	10/31/2019	GJ/Day	25,993		
					137,494		
	Transcanada-Foothills System						
		SPP-F1	10/31/2019	GJ/Day	32,444		
		SPP-F2	10/31/2019	GJ/Day	2,143		
		SPP-F3	10/31/2019	GJ/Day	5,572		
		SPP-F4	10/31/2019	GJ/Day	16,220		
		SPP-F5	10/31/2019	GJ/Day	10,920		
		SPP-F6	10/31/2019	GJ/Day	866		
		SPP-F7	10/31/2019	GJ/Day	26,233		
		SPP-F8	10/31/2019	GJ/Day	10,000		
		SPP-F9	10/31/2023	GJ/Day	15,826		
		SPP-F10	10/31/2019	GJ/Day	15,807		
					136,031		
	Transcanada - GTN System						
		F-02842	10/31/2019	MMBTU/Day		60,000	30,000
		F-02843	10/31/2019	MMBTU/Day		20,270	10,000
		F-07027	4/30/2019	MMBTU/Day		20,000	
		F-07328	10/31/2019	MMBTU/Day	14,000		
		F-07370	10/31/2023	MMBTU/Day	15,000		
		F-07371	10/31/2023	MMBTU/Day	10,099		
		F-07567	10/31/2023	MMBTU/Day	800		
					39,899	100,270	40,000
	Northwest Pipeline						
		10046	6/30/2019	MMBTU/Day	59,696		
		10061	3/31/2019	MMBTU/Day	9,000		
					68,696		
	Paiute						
		F-29	8/31/2019	MMBTU/Day		68,696	61,044
		F-32	3/31/2020	MMBTU/Day		23,000	
						91,696	61,044
	Tuscarora Gas Transmission						
		F001	10/31/2020	MMBTU/Day	105,750		
		F019	10/31/2020	MMBTU/Day	10,000		
		F024	10/31/2020	MMBTU/Day	5,661		
		F025	10/31/2020	MMBTU/Day	5,690		
		F030	10/31/2019	MMBTU/Day	5,722		
		F097	9/30/2030	MMBTU/Day	40,000		
					172,823		
Storage							
	Northwest Pipeline						
		126544 Storage Capacity[1]	3/31/2046	MMBTU	281,242		
		126544 Storage Withdraw[1]	3/31/2046	MMBTU/Day	12,687		
	Paiute						
		S-6 LNG Stor Cap	3/31/2020	MMBTU	303,604		
		S-6 LNG Daily Del Cap	3/31/2020	MMBTU/Day		23,000	

1: Northwest Pipeline storage is currently governed by an asset management agreement with Shell Energy until 10/31/2018.

Many of Sierra's contracts have evergreen clauses and can be renewed for successive one-year extension periods. Given the results of the PROMOD analysis described in Section 2.E of the ESP and the requirement in NAC § 704.9099(3) to maximize the reliability of fuel supply over the term of the ESP, Sierra proposes to continue to renew eligible contracts on an annual basis in order to ensure firm deliveries of gas supplies.

On April 27, 2018, TransCanada's GTN pipeline sent Sierra an email notice stating that it was terminating the evergreen clause for the contract F-07027 and in a phone call it indicated it would do the same in October 2018 for three other contracts. If Sierra and GTN cannot agree on the term for contract renewal, TransCanada GTN will issue an "Open Season" through which other shippers can bid for Sierra's capacity; however Sierra has the Right of First Refusal on all TransCanada GTN contracts, which gives Sierra the ability keep its capacity by matching the terms of the best bid in Open Season.

Sierra purchases firm natural gas supply from a variety of sources, as shown in the table above. Paiute and Tuscarora both deliver gas to a single gas regulating yard at the Tracy Station that feeds Tracy Units 3-5. Tuscarora delivers gas to a separate Tracy Station gas regulating yard feeding Tracy Units 8-10. Therefore, gas supply for Tracy Units 8-10 is primarily dependent on Canadian gas supplies. Contractually, approximately 70,000 MMBtu/day of gas supply can delivered on a firm basis to the Tracy Station site.

Firm gas supplies for Sierra's Ft. Churchill plant are delivered via the Paiute system. Sierra currently holds contracts for firm gas transportation rights on the Paiute system for approximately 61,000 MMBtu/day (summer) and 69,000 MMBtu/day (winter), which serves a majority of the daily natural gas needs at Ft. Churchill.

Sierra maintains natural gas storage assets along both the Paiute and Northwest systems. The Northwest storage is located at the Jackson Prairie facility and allows for unlimited injection/withdrawal cycles subject to then-current mainline pipeline operating conditions. Sierra's total firm storage rights at Jackson Prairie are just over 281,000 MMBtu and come with about 12,600 MMBtu of firm daily injection/withdrawal rights. Sierra similarly holds storage rights the on Paiute system of approximately 304,000 MMBtu of LNG storage capacity that comes with up to 23,000 MMBtu of firm daily withdrawal rights, including firm transport to Sierra's natural gas local distribution company ("LDC") service territory; however, the LNG supply is only available during the winter season. The LNG storage provides short term gas supply for the LDC caused by unforeseen events such as extreme weather patterns or pipeline interruptions.

The Companies' proposed gas transportation strategy for the Action Plan period is set forth in Section 5.B of the 2018 ESP portion of this filing.

2. PHYSICAL GAS PROCUREMENT

The Companies employ a four-season laddering strategy for physical gas purchases, pursuant to which 25 percent of projected monthly gas requirements per season are procured, subject to the availability of conforming bids and the willingness of suppliers to accept reasonable commercial terms. Physical gas volumes are to be procured at indexed prices, subject to a cap of [redacted] per million Btu on the premium. This cap can be exceeded with prior approval from the Risk Committee; however, if the Companies exceed the premium cap and the procured gas which exceeded the premium cap is not the least cost supply alternative, the Company must provide written notice to the Commission's Regulatory Operations Staff ("Staff") and the Bureau of Consumer Protection ("BCP") indicating such. As described in the 2018 ESP portion of this filing, the Companies are proposing to continue to follow the physical gas procurement strategy reviewed and approved in Docket No. 09-07003. Targeted physical gas volumes will exclude any potential gas-fired generation to meet forward sales; gas needed to meet forward sales is only procured through short-term purchases.

During the third quarter of 2018, the Companies will issue a request for proposals for physical gas supply for the period November 2018 through October 2020 as part of the four-season laddering strategy. Figure GAS-5 reflects the planned implementation schedule for the physical gas acquisition strategy.

FIGURE GAS-5
PHYSICAL GAS ACQUISITION STRATEGY

Incremental Transaction	Delivery						
	Winter '18-'19	Summer '19	Winter '19-'20	Summer '20	Winter '20-'21	Summer '21	Winter '21-'22
Q1 '18	25%						
Q3 '18	25%	25%					
Q1 '19	25%	25%	25%				
Q3 '19	25%	25%	25%	25%			
Q1 '20		25%	25%	25%	25%		
Q3 '20			25%	25%	25%	25%	
Q1 '21				25%	25%	25%	25%
Q3 '21					25%	25%	25%
Q1 '22						25%	25%
Q3 '22							25%
Sum	100%	100%	100%	100%	100%	100%	100%

Note: Gas is purchased by season. Winter = November to March, Summer = April to October.

3. EMERGENCY SUPPLIES

Sierra's LDC operations rely on gas supply delivered through interstate pipelines to meet LDC customer requirements. During extreme cold weather events or during a force majeure event on an interstate pipeline, gas supply scheduled to Sierra's gas-fired electric generating plants may be diverted to support LDC gas supply operations, thereby limiting the availability of natural gas supply to meet electric generation requirements. In these infrequent situations, Sierra relies primarily on energy supplies dispatched from Nevada Power generating units and delivered from south to north using the ON Line.

In addition, two of Sierra's generating units, Clark Mountain 3 and 4, are peaking units capable of burning diesel. Sierra maintains diesel inventories at the Clark Mountain facility that can be called upon as an alternate fuel during emergency events only, in order to allow the use of existing pipeline transportation capacity to support peak LDC use. The Reno/Sparks oil terminal is within 10 miles of the Clark Mountain generating units and any required diesel can be supplied on short notice, even during the winter months. Diesel use is anticipated to be minimal, if at all, in each year in the planning period. Diesel inventory replacement is procured, if necessary, utilizing current diesel specifications required ensuring compliance with any operating permit(s) or applicable rule requirements and following internal Corporate Purchasing Policies and Procedures.

D. RENEWABLE ENERGY PLAN (RENEWABLE ENERGY RESOURCES)

1. OVERVIEW

Nevada is fortunate to have significant renewable resources throughout the state, including some of the greatest solar and geothermal potential in the country. The Companies' efforts to incorporate renewable energy into its generating fleet have come a long way in the past decade, and the Companies have built a diverse and robust portfolio of renewable projects through both long-term PPAs and utility-owned renewable projects.

The Companies have clearly articulated their goal of doubling their renewable generating portfolio by 2023. From this perspective, they view Nevada's Renewable Energy Portfolio Standard ("RPS") as a floor, rather than a ceiling, on the share that renewable energy resources contribute to their supply portfolios.

As of June 1, 2018, Nevada Power had approximately 1,017 MW (nameplate) of renewable generating resources operating and delivering renewable energy to meet the dedicated renewable energy needs of its customers.[15] Two additional projects, Techren Solar I (100 MW), and Techren Solar III (25 MW) are in development pipeline. As of June 1, 2018, Sierra had approximately 344 MW (nameplate) of renewable generating resources operating and delivering renewable energy to meet the dedicated renewable energy needs of its customers.[16] Two additional Commission-approved resources, Techren's 200 MW Solar II project and Techren's 25 MW Solar IV project, are in the development pipeline. Techren Solar II is expected to declare commercial operation in July 2019, and Techren Solar IV is expected to declare commercial operation in late Q3 2020.[17]

The follow is a summary of Nevada Power's and Sierra's existing portfolio of renewable facilities that were operating and contributing to meeting Nevada Power's and Sierra's RPS requirements as of June 2018. All capacity figures are nameplate. This listing does not include projects supporting commitments to meet customer-specific requirements for renewable energy under the NGR program.

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[15] The 1,017 MW includes Switch Station I, 100 MW, where Nevada Power uses the energy produced by the facility, but the PCs are dedicated to Switch. It excludes credit only agreements, 3 MW Las Vegas Valley Water District and 13.2 MW Nellis PV. The calculation is based on dividing the Nevada Solar One 69 MW agreement between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission.

[16] The 344 MW total includes the following NGR Agreements, Fort Churchill, 19.5 MW, Boulder Solar II, 50 MW, Switch Station 2, 79 MW, but excludes the Truckee Meadows Water Reclamation district's credit only agreement, 0.8 MW. The 330 MW number is also based upon dividing the Nevada Solar One 69-MW agreement between Nevada Power (46.9 MW) and Sierra (22.1 MW), as previously approved by the Commission.

[17] Sierra and Apple have executed an NGR Agreement related to the output of Techren II.

a. NEVADA POWER RENEWABLE GENERATING FACILITIES

The following is a list of non-NGR dedicated facilities that are operating and contributing to Nevada Power's RPS requirements as of June 2018:

1. Desert Peak 2 Geothermal Power. The Desert Peak 2 facility is a 25 MW geothermal project located in Churchill County, Nevada. The project was approved by the Commission in 2003. It is owned by Ormat Technologies and began producing energy in 2007. The PPA is with Nevada Power and terminates on December 31, 2027.
2. Faulkner 1. Faulkner 1, aka NGP Blue Mountain, is a 49.5 MW geothermal project located in Humboldt County near Blue Mountain, Nevada. The project was approved by the Commission in 2007. It is owned by Alternative Earth Resources, Inc. and began producing energy in 2009. The PPA is with Nevada Power and terminates on December 31, 2029.
3. Galena 2 Geothermal Power Plant. The Galena 2 facility is a 13 MW geothermal project located in Washoe County south of Reno near Steamboat, Nevada. The project was approved by the Commission in 2003. It is owned by Ormat Technologies and began producing energy in 2007. The PPA is with Nevada Power and terminates on December 31, 2027.
4. Jersey Valley Geothermal Project. The Jersey Valley facility is a 22.5 MW geothermal project located in a remote area in both Lander and Pershing counties in Nevada. The project was approved by the Commission in 2007. It is owned by Ormat Technologies and began producing energy in 2011. The PPA is with Nevada Power and terminates on December 31, 2031.
5. McGinness Hills Geothermal Project. The McGinness Hills facility is a 96 MW geothermal project located in a remote area in Lander County, Nevada. The project was approved by the Commission in 2010. It is owned by Ormat Technologies and began producing energy in 2012. As part of the existing 20-year PPA between Nevada Power and ORNI 39, LLC (owned by Ormat Technologies, Inc.), the McGinness Hills geothermal facility was expanded to include a second 48 MW geothermal unit (included in 98 MW total). The second unit declared contractual commercial operation on February 4, 2015. The Commission approved the expansion on December 23, 2013 (Docket No. 13-11007). The PPA terminates on December 31, 2032.
6. Salt Wells Geothermal Plant. The Salt Wells facility is a 23.6 MW geothermal project located in Churchill County east of Fallon, Nevada. The project was approved by the Commission in 2007. It is owned by Enel North America and began producing energy in 2009. The PPA is with Nevada Power and terminates on December 31, 2029.
7. Stillwater 2 Geothermal Plant. The Stillwater 2 facility is a 47.2 MW geothermal project located in Washoe County, Nevada. The project was approved by the Commission in 2007.

It is owned by Enel North America and began producing energy in 2009. The PPA is with Nevada Power and terminates on December 31, 2029.

8. Tuscarora Geothermal Plant. The Tuscarora facility is a 32 MW geothermal project. The capacity of the facility was amended from 25 MW to 32 MW in Docket No. 12-06053, and the PPA was amended to allow for further capacity increases to up to 50 MW. The project is owned by Ormat Technologies and began producing energy in 2012. The PPA is with Nevada Power and terminates on December 31, 2032.

9. ACE Searchlight Solar. ACE Searchlight, now Searchlight Solar, is a 17.5 MW solar PV project near Searchlight, Nevada. The project was approved by the Commission in 2009. The project began producing energy in 2014. It is owned by Searchlight Solar, LLC. The PPA is with Nevada Power and terminates on December 31, 2034.

10. Apex Nevada Solar. The Apex Nevada Solar facility is a 20 MW solar PV project located in Clark County north of Las Vegas, Nevada. The project was approved by the Commission in 2009. It is owned by Southern Renewable Energy and began producing energy in 2012. The PPA is with Nevada Power and terminates on December 31, 2037.

11. Boulder Solar 1. Boulder Solar 1 is a 100 MW solar PV project located in Boulder City, Nevada. The project was approved by the Commission in 2015. The solar facility completed commissioning and declared commercial operating in December 2016. The 25-year PPA terminates on December 31, 2036. Nevada Power entered into a three-year NGR agreement with the City of Las Vegas whereby 43,200 kPCs are transferred annually from this facility to the City.[18]

12. Crescent Dunes. Crescent Dunes is a 110 MW solar thermal plant with storage capability located near Tonopah, Nevada. The project was approved by the Commission in 2010. The facility is owned by Tonopah Solar Energy, LLC. The generating facility completed commissioning and declared commercial operation in November 2015. The PPA terminates on December 31, 2040.

13. Las Vegas Valley Water District ("LVVWD"). The LVVWD projects comprise of six Las Vegas-area solar PV projects totaling 3 MW owned and operated by PowerLight Corporation. The projects were approved by the Commission in 2006. These installations began producing electricity in 2006 and 2007. The agreement terminates on December 31, 2026.

14. Mountain View Solar. The Mountain View facility is a 20 MW solar PV plant located north of Las Vegas in Clark County, Nevada. The project was approved by the Commission in

[18] The three year NGR with the City of Las Vegas was approved by the Commission in Docket No. 15-11026.

2012. The facility is owned by NextEra Energy and began producing energy in 2014. The project declared commercial operation in January 2014. The PPA terminates on December 31, 2039.

15. Nellis Air Force Base, Solar Star. The Nellis AFB PV project is a 13.2 MW solar PV project that produces energy for Nellis Air Force Base, located north of Las Vegas, Nevada. The project was approved by the Commission in 2007. The project is owned by Fotowatio and began producing electricity in 2007. The PPA terminates on December 31, 2027.

16. Nellis Solar Array II. Nellis Solar Array II is a 15 MW (name plate AC) solar PV project located on Nellis Air Force Base in Las Vegas. Nevada. The solar array began producing energy in 2015. The project was approved by the Commission in Docket No. 14-05003. The project is owned by Nevada Power.

17. Nevada Solar One. Nevada Solar One is a 69 MW concentrating solar thermal plant that is located in the Eldorado Valley near Boulder City, Nevada. Approximately 46.9 MW of the capacity and generation is contracted to Nevada Power. The balance of the capacity and generation is contracted to Sierra. The project was approved by the Commission in 2003. It is owned and operated by Acciona Solar Power and began producing energy in 2007. The PPA terminates on December 31, 2027.

18. Silver State Solar. The Silver State Solar facility is a 52 MW solar PV project located in Clark County near Primm, Nevada. The project was approved by the Commission in 2010. It is owned by Enbridge and began producing energy in 2012. The PPA terminates on December 31, 2037.

19. Spectrum Nevada Solar. The Spectrum facility is a 30 MW solar PV plant located north of Las Vegas in Clark County, Nevada. The project was approved by the Commission in 2012. It is owned by Southern Renewable Energy and began producing energy in 2013. The PPA terminates on December 31, 2038.

20. Stillwater 2 Solar. The Stillwater 2 Solar facility is a 22-MW solar PV project located in Washoe County, Nevada. The project was approved by the Commission in 2011. It is owned by Enel North America and began producing energy in 2012. The agreement terminates on December 31, 2029.

21. Spring Valley Wind. The Spring Valley Wind facility is a 151.8 MW wind project is located in Spring Valley near Ely, Nevada. The project was approved by the Commission in 2010. It is owned by Pattern Energy and began delivering energy in 2012. The PPA terminates on December 31, 2032.

22. Apex Landfill Facility. The Apex Landfill facility is a 12 MW landfill gas-to-energy project located in Clark County, Nevada. The project was approved by the Commission in 2009. It is owned by Energenic and began producing energy in 2012. The PPA terminates on December 31, 2032.

23. Lockwood Renewable Energy Facility. The Lockwood facility is a 3.2 MW landfill gas-to-energy project located at the Lockwood Landfill near Reno, Nevada. The project was approved by the Commission in 2010. It is owned by Waste Management and began producing energy in 2012. The PPA terminates on December 31, 2032.

24. Goodsprings Recovered Energy Generation Station. The Goodsprings Recovered Energy Generation Station is located 35 miles south of Las Vegas, Nevada. It is a 7.5 MW generating plant which converts waste heat from a natural gas pipeline compressor station to electric energy. The project was approved by the Commission in 2008. It started producing energy in 2010. The project is owned by Nevada Power.

b. SIERRA RENEWABLE GENERATING FACILITIES

The following is a list of non-NGR dedicated facilities that are operating and contributing to Sierra's RPS requirements as of June 2018:

1. Beowawe Geothermal Power Plant. The Beowawe facility is a 17.7 MW geothermal facility located in Eureka County and is owned by Terra-Gen Power. The plant was placed into service in 1985 and was originally under contract with Southern California Edison, but in 2006 Sierra entered into a 20-year contract for renewable energy that expires on April 21, 2025.

2. Brady Geothermal Power Plant. The Brady facility is a 24 MW geothermal facility located in Churchill County northeast of Fernley, Nevada. The project is owned by Ormat Technologies and started producing energy in 1992. Sierra has a 30-year PPA with the facility that expires on July 29, 2022.

3. Burdette Geothermal Power Plant. The Burdette facility is a 26 MW geothermal project located in Washoe County near Steamboat, Nevada. The project is owned by Ormat Technologies and went into service in 2006. Sierra has a 20-year PPA with the facility that expires on December 31, 2026.

4. Galena 3 Geothermal Power Plant. The Galena 3 facility is a 26.5 MW geothermal project located in Washoe County south of Reno near Steamboat, Nevada. The project is owned by Ormat Technologies and went into service in 2008. Sierra has a 20-year PPA with the facility that expires in 2028.

5. Homestretch Geothermal Power Plant. The Homestretch facility is a 5.58 MW geothermal project located in Lyon County north of Yerington, Nevada. Sierra originally entered into separate contracts for three small Homestretch geothermal plants that totaled 2.1 MW.

Sierra obtained Commission approval to aggregate and expand the project in Docket No. 09-01016; the original long-term contract expired in 2017. It was extended for one year and assuming that it is not further extended, is currently set to expire on December 31, 2018.

6. Soda Lake 1 & 2 Geothermal Power Plants. The Soda Lake 1 & 2 geothermal facilities combine for 23.1 MW and are located in Churchill County east of Fallon, Nevada. The Soda Lake 1 PPA, the smaller of the two generating units at 3.6 MW, expired in 2017 but the agreement was extended through December 31, 2018. There is an option to further extend through 2020. Soda Lake 2, the larger unit at 19.5 MW, PPA expires on August 4, 2021.

7. Steamboat 2 Geothermal Power Plant. The Steamboat 2 facility is a 13.4 MW geothermal project located in Washoe County, NV. The project is owned by Ormat Technologies and began producing energy in 1992. Sierra has a 30 year contract with the facility that expires on December 31, 2022.

8. Steamboat 3 Geothermal Power Plant. The Steamboat 3 facility is a 13.4 MW geothermal project located in Washoe County, Nevada. The project is owned by Ormat Technologies and began producing energy in 1992. Sierra has a 30-year PPA with the facility that expires on December 18, 2022.

9. USG San Emidio Geothermal Power Plant. The USG San Emidio facility is an 11.75 MW geothermal project located just inside the eastern border of Washoe County, Nevada. The project is owned by U.S. Geothermal Inc. Sierra originally entered into a 30-year long-term PPA in 1986 fora 3.8 MW geothermal power plant. Sierra received Commission approval for an amended and restated PPA in Docket No. 11-08010. Sierra has a 25 year contract with the facility that expires on December 31, 2037.

10. Nevada Solar One. The Nevada Solar One facility is a 69 MW concentrating solar thermal plant located in Eldorado Valley near Boulder City, Nevada. The project is owned and operated by Acciona Solar Power and came online in 2007. Sierra purchases 22.1 MW from the facility with the balance purchased by Nevada Power. Nevada Power's and Sierra's PPA with the facility expires on December 31, 2027.

11. Fleish Hydro Power Plant. The Fleish facility is a 2.4 MW hydro-electric project located on the California/Nevada border southwest of Reno, Nevada. The project is owned by Truckee Meadows Water Authority ("TMWA") and went into commercial operation in 2008. Sierra has a 20-year PPA with the facility that expires on June 1, 2028.

12. New Lahontan Truckee Carson Irrigation District Hydro Power Plant. The New Lahontan facility is a 4 MW hydro-electric plant located in Lahontan, Nevada. The project is owned and operated by the Truckee Carson Irrigation District and went into commercial operation in 1989. Sierra has a 50-year PPA with the facility that expires in June 11, 2039.

13. Verdi Hydro Power Plant. The Verdi facility is a 2.4 MW hydro-electric project located in Washoe County, Nevada. The project is owned by the Truckee Meadows Water Authority

and went into service in 2009. Sierra has a 20 year contract with the facility that expires on June 1, 2029.

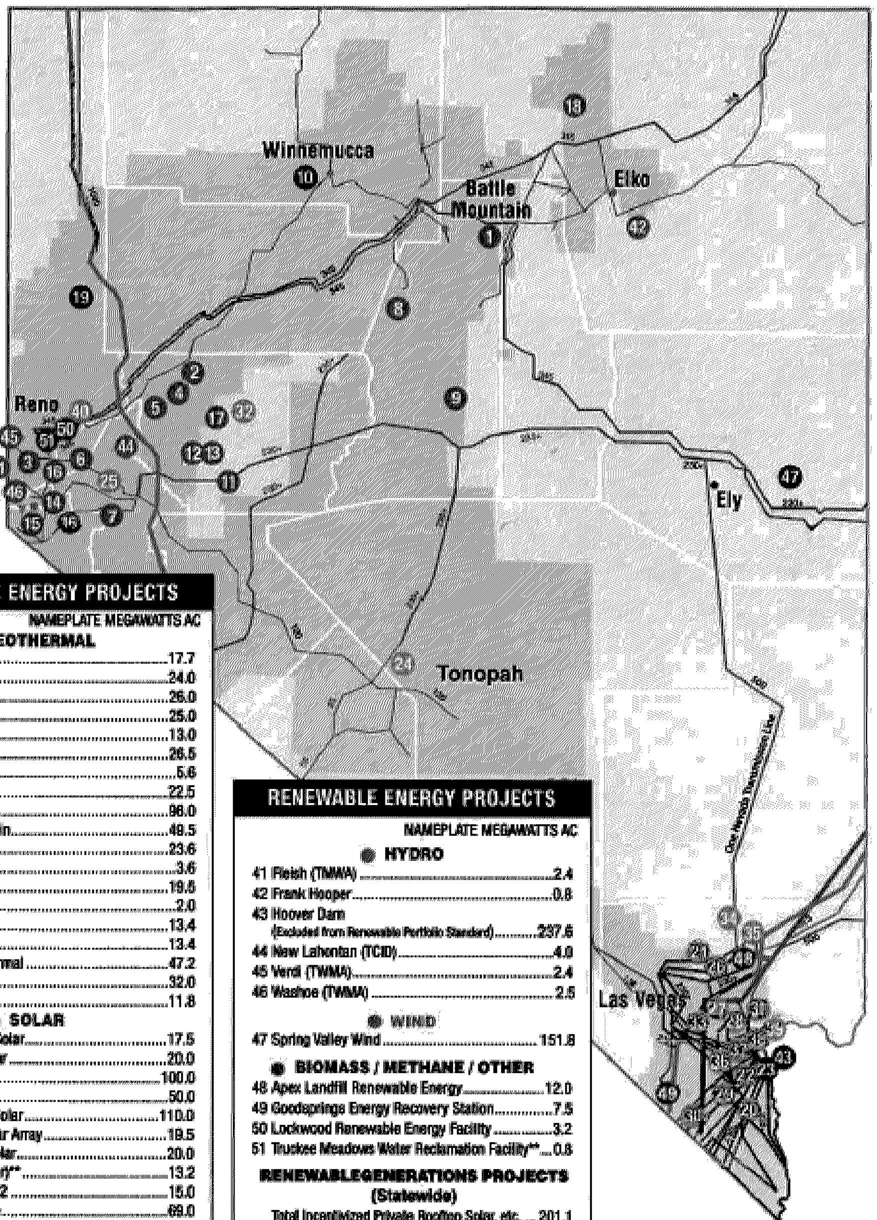
14. Washoe Hydro Power Plant. The Washoe facility is a 2.5 MW hydro-electric project located in Washoe County, NV. The project is owned by the TMWA and went into service in 2008. Sierra has a 20-year PPA with the facility that expires in June 1, 2028.

15. Truckee Meadows Waste Water Facility ("TMWWF"). The TMWWF is 0.8 MW biogas facility where Sierra has a PC only purchase agreement. The agreement was approved by the Commission in 2006. The 20-year contract expires on December 12, 2024.

Figure REN-1 below is a map showing all renewable facilities owned by or under contract with Nevada Power and Sierra. The map includes renewable facilities that do not qualify for the RPS (e.g., Hoover), and renewable facilities where the PCs are assigned to a customer under an NGR agreement and cannot be used by Companies towards meeting the RPS.

FIGURE REN-1
RENEWABLE ENERGY PROJECTS OWNED OR UNDER CONTRACT

NV Energy's Clean Energy Commitment



RENEWABLE ENERGY PROJECTS

	NAMEPLATE MEGAWATTS AC
GEOTHERMAL	
1 Beowawe Power	17.7
2 Brady	24.0
3 Burdette	26.0
4 Desert Peak 2	25.0
5 Galena 2	13.0
6 Galena 3	26.5
7 Homestretch	5.6
8 Jersey Valley	22.5
9 McGinness Hills	96.0
10 NGP Blue Mountain	49.5
11 Salt Wells	23.6
12 Soda Lake 1	3.6
13 Soda Lake 2	19.5
14 Steamboat 1A**	2.0
15 Steamboat 2	13.4
16 Steamboat 3	13.4
17 Stillwater Geothermal	47.2
18 Tuscarora	32.0
19 USG San Emidio	11.8
SOLAR	
20 ACE Searchlight Solar	17.5
21 Apex Nevada Solar	20.0
22 Boulder Solar I	100.0
23 Boulder Solar II	50.0
24 Crescent Dunes Solar	110.0
25 Fort Churchill Solar Array	19.5
26 Mountain View Solar	20.0
27 Nellis 1 (Solar Star)**	13.2
28 Nellis Solar Array 2	15.0
29 Nevada Solar One	69.0
30 Silver State Solar North	52.0
31 Spectrum Nevada Solar	30.0
32 Stillwater Solar PV	22.0
33 SunPower (Las Vegas Valley Water District)**	3.0
34 Switch Station 1	100.0
35 Switch Station 2	79.0
36 Techren Solar 1*	100.0
37 Techren Solar 2*	200.0
38 Techren Solar 3*	25.0
39 Techren Solar 4*	25.0
40 Turquoise Solar*	50.0

* Pending regulatory approval, in development or under construction.
** Portfolio credits only

RENEWABLE ENERGY PROJECTS

	NAMEPLATE MEGAWATTS AC
HYDRO	
41 Fleish (TMWA)	2.4
42 Frank Hooper	0.8
43 Hoover Dam (Excluded from Renewable Portfolio Standard)	237.6
44 New Lahontan (TCID)	4.0
45 Verdi (TWMA)	2.4
46 Washoe (TWMA)	2.5
WIND	
47 Spring Valley Wind	151.8
BIOMASS / METHANE / OTHER	
48 Apex Landfill Renewable Energy	12.0
49 Goodsprings Energy Recovery Station	7.5
50 Lockwood Renewable Energy Facility	3.2
51 Truckee Meadows Water Reclamation Facility**	0.8
RENEWABLEGENERATIONS PROJECTS (Statewide)	
Total Incentivized Private Rooftop Solar, etc.	201.1
Total NV Energy Clean Energy Resources (MW)	**2,218.6**

ENERGY EFFICIENCY

Peak Demand Reduction
Statewide .... 519 Megawatts
Calculated for Years 2005 through 2017

NV Energy

Updated 03-07-2018

2. RPS COMPLIANCE OUTLOOK

Compliance with the RPS is mandated by statute, and planning to comply with the RPS requires a significant planning effort. Nevada's RPS is set forth at NRS § 704.7821, and is based on a percentage of the total amount of electricity sold to retail customers in Nevada. The RPS currently is set at 20 percent, meaning that not less than 20 percent of the energy Nevada Power and Sierra sell to their retail customers in Nevada must be generated, acquired or served from qualified renewable systems and sources. The RPS increases to 22 percent in 2020, before increasing to 25 percent in 2025. The RPS relies on a Portfolio Credit or PC system, and contains a solar "carve out" that requires that a minimum of 6 percent of the overall PC requirement be met with PCs from solar resources. The RPS has also been amended to phase out PCs from demand side measures (including demand response programs), and authorizes PCs for station usage from only geothermal power plants.

In their most recent RPS Annual Compliance filing (Docket No. 18-03044), Nevada Power and Sierra both demonstrated that they exceeded their 2017 RPS requirement, as well as the 2017 solar requirement. Nevada Power ended 2017 with RPS compliance of 23.1 percent of retail sales, with 44.5 percent of those PCs sourced from solar thermal and PV. Sierra ended 2017 with RPS compliance of 25.5 percent of retail sales, with 31.0 percent of those PCs sourced from solar thermal and PV.

a. NEVADA POWER RPS COMPLIANCE

Nevada Power's compliance outlook can best be summarized as positive, but there are risks that could shift Nevada Power's compliance outlook to tenuous. The primary reason for this caution is the Crescent Dunes facility. Crescent Dunes is a large, 110 MW, solar thermal generator that was expected to deliver in excess of 500,000 kPCs per year. Since declaring commercial operation in late 2015, Crescent Dunes has experience frequent and prolonged outages. The current IRP/ESP outlook reduces the expected amount of energy from this plant by 75 percent in 2019, 50 percent in 2020, and 25 percent in 2021. Given the size of the project, Nevada Power simply does not have enough PC reserves nor sufficient new renewable capacity in the pipeline to overcome lasting, multi-year PC shortfalls. Although, Nevada Power is positioned to meet its future PC commitments (RPS compliance, NGR agreements, Sierra PC-pool repayments, and NRS Chapter 704B obligations), However, experience has shown that renewable projects, both operating and pipeline, can be unpredictable. Even if Crescent Dunes is able to resolve all of its operating issues, issues may arise with other renewable resources, or attrition of projects may impact compliance.

Nevada Power is seeking the approval of three PPAs totaling approximately 600 MW in this Joint IRP.[19] This additional renewable capacity will not only address potential performance uncertainty

[19] IRP Renewable Case, Eagle Shadow Mountain Solar (300 MW), Copper Mountain 5 (250 MW) and Techren 5 (50 MW)

associated with Crescent Dunes, it also allows Nevada Power to take advantage of current favorable renewable pricing for the benefit its customers. Approval of these agreements will safeguard Nevada Power's ability to meet its future RPS obligations under current law, and positions it to achieve its goal of going above and beyond the RPS by making renewable energy a significant component of its energy supply strategy. If approved, the three PPAs will also allow Nevada Power be ahead of the curve when it comes to realigning its generating portfolio in anticipation of potential increases to the current RPS requirement.

b. SIERRA RPS COMPLIANCE

Sierra's current renewable portfolio simply does not generate enough PCs to sustain its future RPS compliance. This is due to expiring long-term contracts for which replacement contacts have not been secured. Sierra can manage this situation in the short term by drawing down on PCs banked from prior years and by utilizing PC repayments from Nevada Power. However, both options will only extend compliance by a few years. By 2021, the credit bank will be drawn down to near zero (27,000 kPCs), and Nevada Power will have fully repaid its credit obligation to Sierra. To address the impending PC shortfall, Sierra is seeking the approval of approximately 401 MW of new renewable generation in this filing[20]. This new generation is projected to declare commercial operation in mid-to-late 2021, which will ensure Sierra's compliance with the RPS.

Similar to Nevada Power, the 401 MW is more than what is required for Sierra to maintain RPS compliance. However, approval of the three PPAs not only safeguards Sierra's ability to meet its future RPS obligations under current law, it also positions Sierra to achieve its objective of going above and beyond the RPS by making renewable energy a significant component of its energy delivery strategy. The additional renewable generation also allows Sierra to get ahead of the curve when it comes to realigning its generating portfolio in anticipation of potential increases to the current RPS requirement.

3. PLANNING FOR RPS COMPLIANCE IN THE FUTURE

The Companies vigilantly plan to meet future PC requirements, recognizing there are still uncertainties and risks inherent in renewable energy production and renewable project development. The RPS planning strategy incorporates all current Nevada requirements, with the primary objective of fully complying with the RPS.

For this IRP, the Companies developed renewable expansion plans under various load scenarios. All expansion plans assume full compliance with an escalating RPS based on the forecasted load projection. The annual RPS credit requirements were calculated in compliance with NRS § 704.7821, which sets forth the annual PC requirement for the Companies based on a percentage of

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20 IRP Renewable Case, Dodge Flat Solar (200 MW), Fish Springs Ranch Solar (100 MW) and Battle Mountain Solar (101 MW)

total electricity sold to their retail customers during a calendar year. The expected PC supply was determined starting with the current portfolio of approved projects, both operating and under development or contemplated by the Companies.

Several assumptions are built into the forecast.

- Existing contracts expire in accordance with the contract terms and are not automatically renewed;[21]
- The Companies adjusts the expected amount of energy and credit from renewable facilities for the period of 2018-2021 in cases where the historic generation, based on two or more years of data, consistently varied from that of the contractual or expected supply table. This is consistent with the methodology that the Companies used for the past several years in developing its annual ESPs. This adjustment recognizes that options to address underperformance within a shorter planning window are limited. It also aligns the short-term and long-terms plans;[22]
- PCs from the RenewableGenerations incentive programs will continue until funds are exhausted and/or the programs expire in 2021, and solar systems placed into service after 2015 do not qualify for the solar multiplier. The plan assumes that the number of credits for Renewable Generations will plateau in 2022 and then remain flat;
- The plan assumes that the percent of annual PC requirements met from energy efficiency and conservation measures would be limited to no more than 20 percent of the credit total, decreasing to no more than 10 percent of the total in 2020, and finally 0 percent of the total starting in 2025;
- Surplus PCs are carried forward without limitation, the plan assumes no surplus PC sales;
- The plan contemplates that Nevada Power will continue to repay its credit obligation to Sierra, with all credits fully repaid by 2021 (which is before Sierra would have a need to add a new project);[23]
- The plan assumes that generation from both company-owned PV systems and PPA projects would be degraded starting the year following the first full year of operation;

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21 This does not imply that the Companies would rule out renewing existing agreements. Rather, it recognizes the uncertainty as to whether the resource could continue to support ongoing generation, and whether the Companies and the counterparty can come to terms on renewing the agreement.

22 Additional information on the short-term adjustments is contained in Section 2.D of the ESP narrative.

23 The repayment over a four year period is a modeling protocol in the renewable planning process but is not intended to reflect how and when actual repayments would be made since such amounts would be depend on the factual circumstances that will occur during this time period (*e.g.*, load, renewable generation, changes in law, etc.).

- Geothermal projects and placeholders would continue to qualify for station usage credits; all other technologies would no longer qualify;[24]
- The plan accounts for all Commission approved NGR agreements as of June 2018 where PCs associated with all or a portion of the output from a renewable facility(s) has been assigned to a customer under the NGR tariff, and therefore cannot be used by the Companies in meeting their RPS credit requirements;
- The plan assumes no further changes to the existing statutory and regulatory regime; and;
- Finally, the Preferred Plan assumes the approval of three new Sierra PPAs and three new Nevada Power PPAs. If approved, the Companies will not realize the full benefit of these projects until 2022.

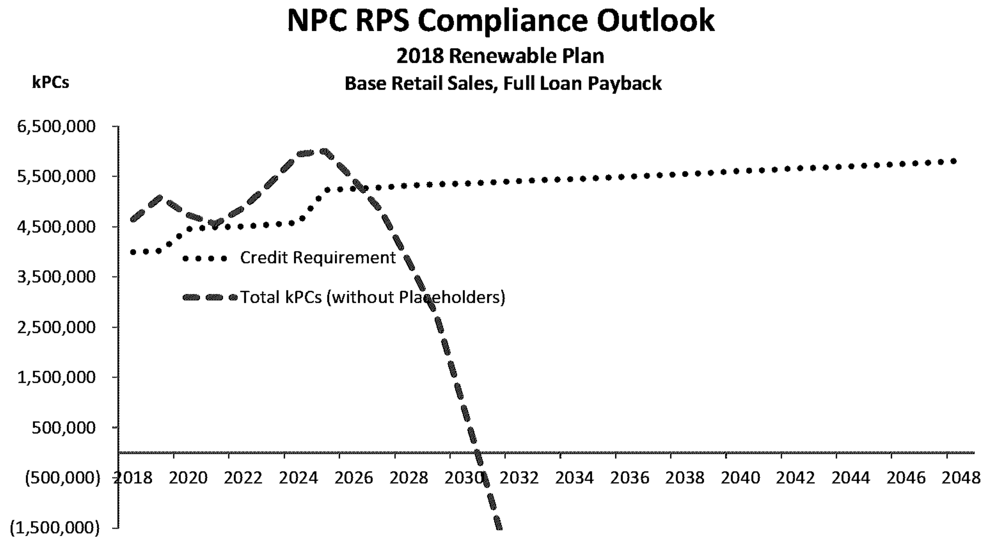
As in the past plans, generic placeholders were added to address future RPS requirements outside the Action Plan period that are not met through existing or proposed contracts. Because all placeholders occur after the current Action Plan period, placeholders do not imply the Companies' intention to develop these projects. Instead, if a decision to fill an open RPS requirement falls within an Action Plan period, as they have done here, the Companies would undertake a request for proposals to determine the best option to meet the RPS when new resources are needed. Thus the underlying assumption can be revisited if other more economical options are presented at that time. Placeholder pricing for this IRP was based on the results of the 2018 renewable RFP bids. Pricing for both geothermal and solar PV placeholder projects was adjusted by two percent annually to account for inflation. Solar PV prices were also adjusted starting in 2022 to reflect the phasing out of the solar Investment Tax Credit ("ITC"). The ITC is scheduled to drop to 26 percent in 2020, 22 percent in 2021 and finally 10 percent in 2022.

After developing the renewable baseline forecast, the Companies added placeholder projects to ensure that the Companies both modeled to meet or exceed RPS compliance, or to replace renewable energy that is expected to be lost due to expiring contracts. The renewable expansion plans all were developed assuming full compliance throughout the 30-year planning horizon.

The following figures illustrate the RPS compliance projections for Nevada Power and Sierra. The first set of charts assume no actions are taken to add new renewable resources. Both figures are based on each Company's current renewable portfolio and above planning protocol under the base load projections.

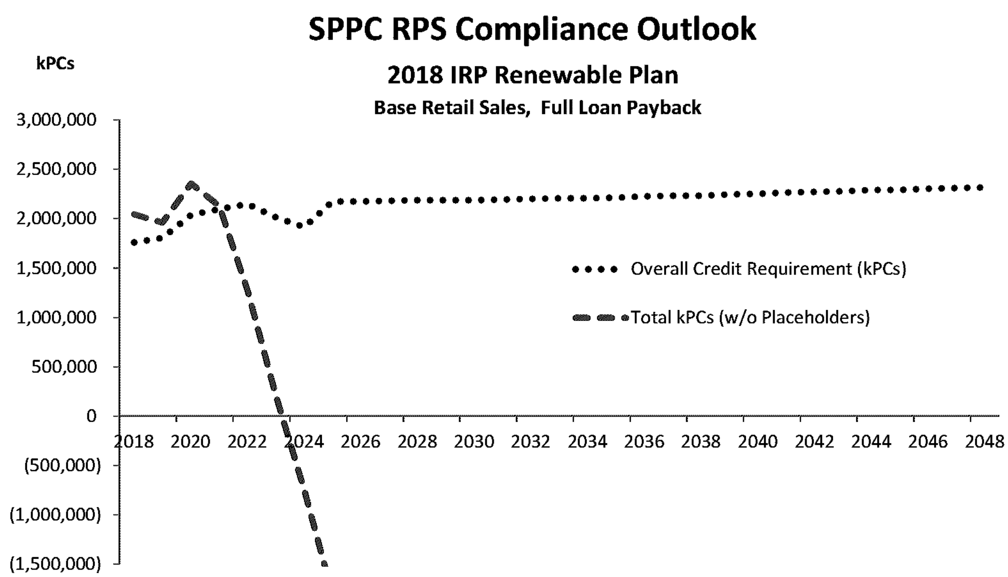
[24] The long term planning outlook for both Nevada Power and Sierra does include geothermal placeholders until 2035. Although the Company is not seeking the approval of any geothermal PPAs as a result of the 2018 Renewable RFP, this does not rule out the possibility of adding geothermal resources in the future.

FIGURE REN-2
NEVADA POWER RPS OUTLOOK CURRENT & APPROVED PROJECTS ONLY
(NO EXTENSIONS, PLACEHOLDERS, OR PURCHASES)



Based on the above Nevada Power is projected to be RPS non-compliant in 2027.

FIGURE REN-3
SIERRA RPS OUTLOOK CURRENT & APPROVED PROJECTS ONLY
(NO EXTENSIONS, PLACEHOLDERS, OR PURCHASES)

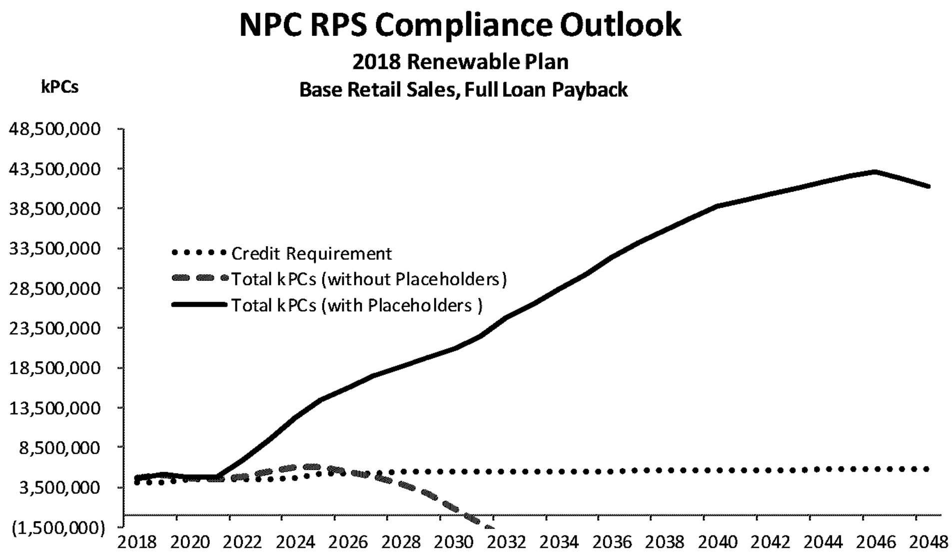


Based on the above, Sierra is projected to be RPS non-compliant in 2022.

The figures below show Nevada Power's and Sierra's respective RPS compliance outlooks assuming the approval of the six PPAs, as presented in the both the Low Carbon Case (the Preferred Plan) and the Renewable Case (the Alternative Plan).

The surge in a total number of kPCs available to meet the RPS requirement, solid black line on the charts below, is due to credit banking. As discussed above, both plans assume that all excess PCs are banked, not sold, and both assume unlimited banking. The plans also assumes that the Companies will replace expiring renewable contacts throughout the planning horizon in order to maintain renewable capacity.

FIGURE REN-4
NEVADA POWER'S RPS OUTLOOK
THE THREE PPAS PLUS 150 MW, BASE RETAIL SALES



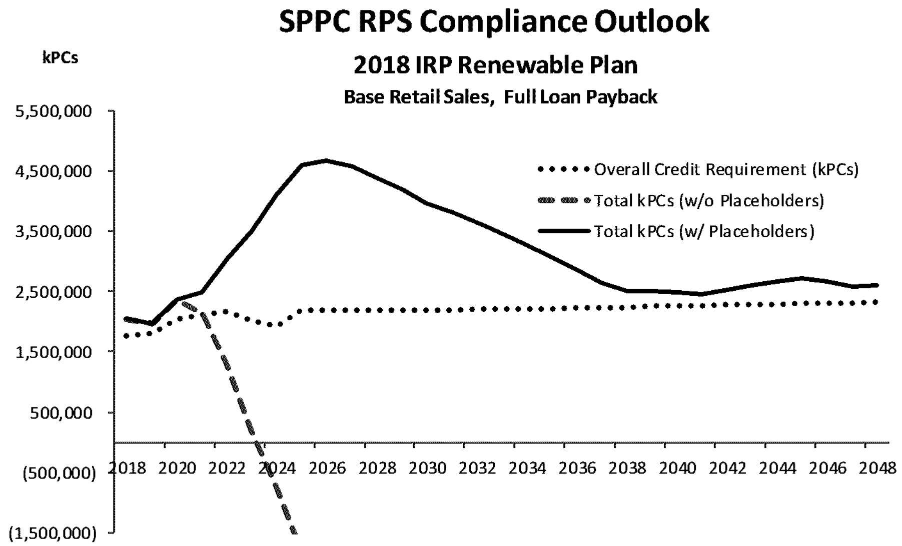
Projected RPS credit short-fall assuming no Placeholder Projects >> **2027**

		Project	MW	COD MTH/YR	
ER RFP	>	8minutenergy, Eagle Shadow Mountain Solar	300.0	1	2022
ER RFP	>	Sempra 1.0 Copper Mountain 5	250.0	1	2022
ER RFP	>	174 Power Global 1 Techren V	50.0	1	2021
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2023 *
Placeholder	>	PPA PV SN 25 MW Tracking (2X)	50.0	1	2023 *
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2030
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2030
Placeholder	>	PPA PV SN 25 MW Tracking (2X)	50.0	1	2030
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2031
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2031
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2032
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2032
Placeholder	>	PPA PV SN 25 MW Tracking (2X)	50.0	1	2032
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder	>	PPA Geo NN 25 MW (2X)	50.0	1	2035
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2044
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2048
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2048
		Total NPC	2,100.0		

* additional capacity that is needed to double total operating capacity by 2023.

The above placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

FIGURE REN-5
SIERRA'S RPS OUTLOOK
THE THREE PPAS PLUS 150 MW, BASE RETAIL SALES



Projected RPS credit short-fall assuming no Placeholder Projects >> **2022**

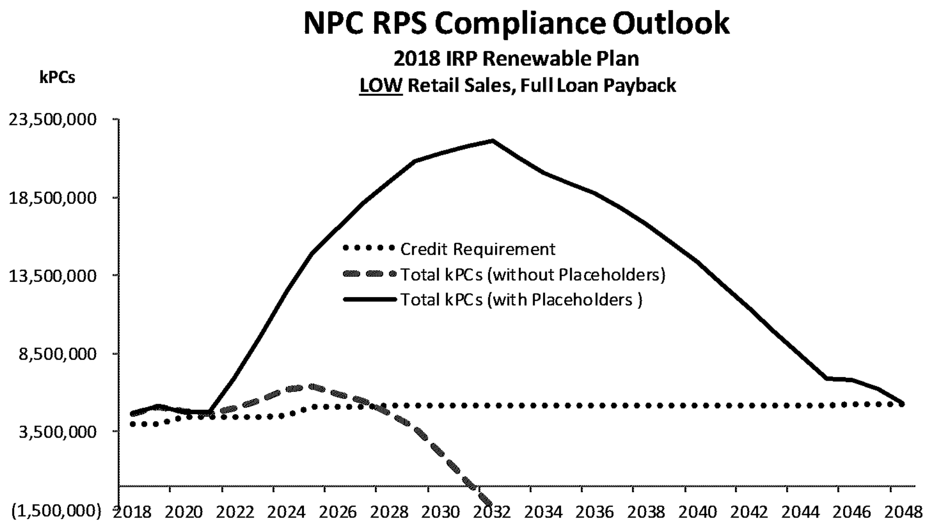
		Project	MW	COD MTH	YR	
ER RFP	>	NextEra 1.0 Dodge Flat	200.0	9	2021	
ER RFP	>	NextEra 3.0 Fish Springs Ranch Solar	100.0	12	2021	
ER RFP	>	Cypress Creek 1.0 Battle Mountain	101.0	6	2021	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2022	*
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2023	*
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2029	
Placeholder	>	PPA PV NN 25 MW Tracking (1X)	25.0	1	2031	
Placeholder	>	PPA PV NN 25 MW Tracking (3X)	75.0	1	2038	
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2039	
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2042	
Placeholder	>	PPA Geo NN 25 MW (2X)	50.0	1	2047	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2047	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2047	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2047	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2048	
Total SPPC		Total	1,251.0			

* additional capacity that is needed to double total operating capacity by 2023

The above placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

Figures REN-6 and REN-7 below show Nevada Power's and Sierra's RPS compliance outlook with the same assumptions under a low retail sales outlook.

FIGURE REN-6
NEVADA POWER'S RPS OUTLOOK
THREE PPAS PLUS 150 MW LOW RETAIL SALES



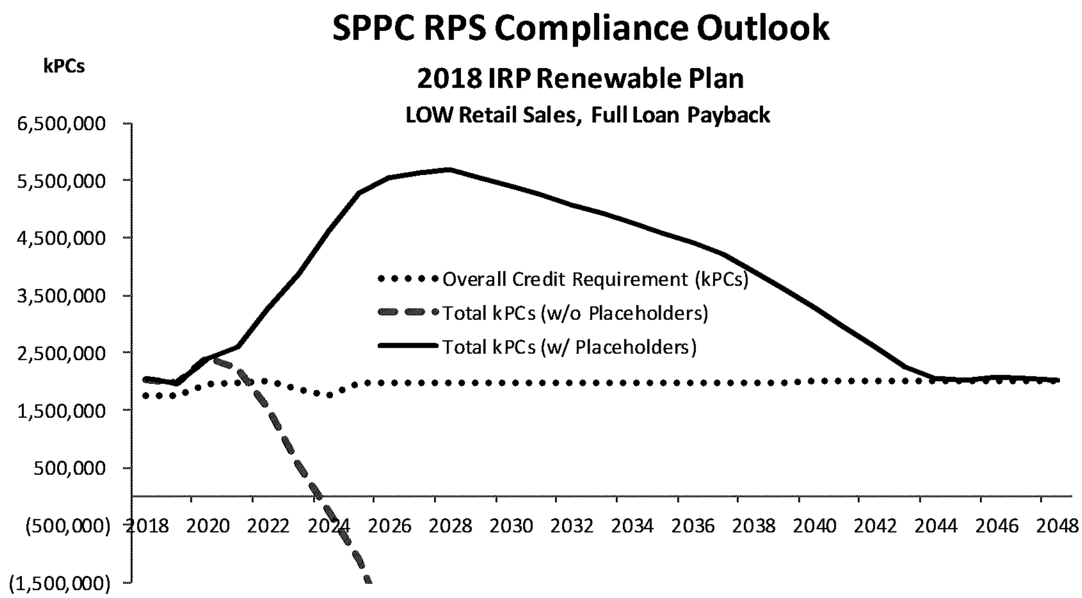
Projected RPS credit short-fall assuming no Placeholder Projects >> **2028**

		Project	MW	COD MTH/YR	
ER RFP	>	8minutenergy Eagle Shadow Mountain Solar	300.0	1	2022
ER RFP	>	Sempra 1.0 Copper Mountain 5	250.0	1	2022
ER RFP	>	174 Power Global 1 Techren V	50.0	1	2021
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2023 *
Placeholder	>	PPA PV SN 25 MW Tracking (2X)	50.0	1	2023 *
Placeholder	>	PPA Geo NN 25 MW (2X)	50.0	1	2035
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2041
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2044
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2046
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2046
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2046
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2046
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2046
		Total NPC	1,500.0		

* additional capacity that is needed to double total operating capacity by 2023

The above placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

FIGURE REN-7
SIERRA'S RPS OUTLOOK
THREE PPAS PLUS 150 MW, LOW RETAIL SALES



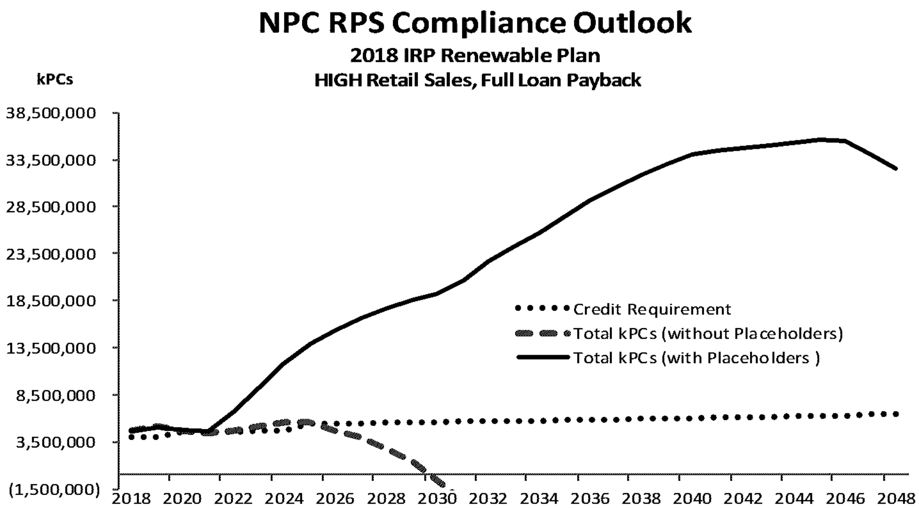
		Project	MW	COD MTH/YR		
ER RFP	>	NextEra 1.0 Dodge Flat	200.0	9	2021	
ER RFP	>	NextEra 3.0 Fish Springs Ranch Solar	100.0	12	2021	
ER RFP	>	Cypress Creek 1.0 Battle Mountain	101.0	6	2021	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2022	*
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2023	*
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2044	
Placeholder	>	PPA PV NN 25 MW Tracking (3X)	75.0	1	2045	
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2046	
Placeholder	>	PPA Geo NN 25 MW (2X)	50.0	1	2047	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2047	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2047	
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2047	
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2048	
Total SPPC		Total	1,126.0			

* additional capacity that is needed to double total operating capacity by 2023

The above placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

Figures REN-8 and REN-9 below show Nevada Power's and Sierra's RPS compliance outlook with the same assumptions under a high retail sales outlook.

FIGURE REN-8
NEVADA POWER'S RPS OUTLOOK
THREE PPAS PLUS 150 MW, HIGH RETAIL SALES



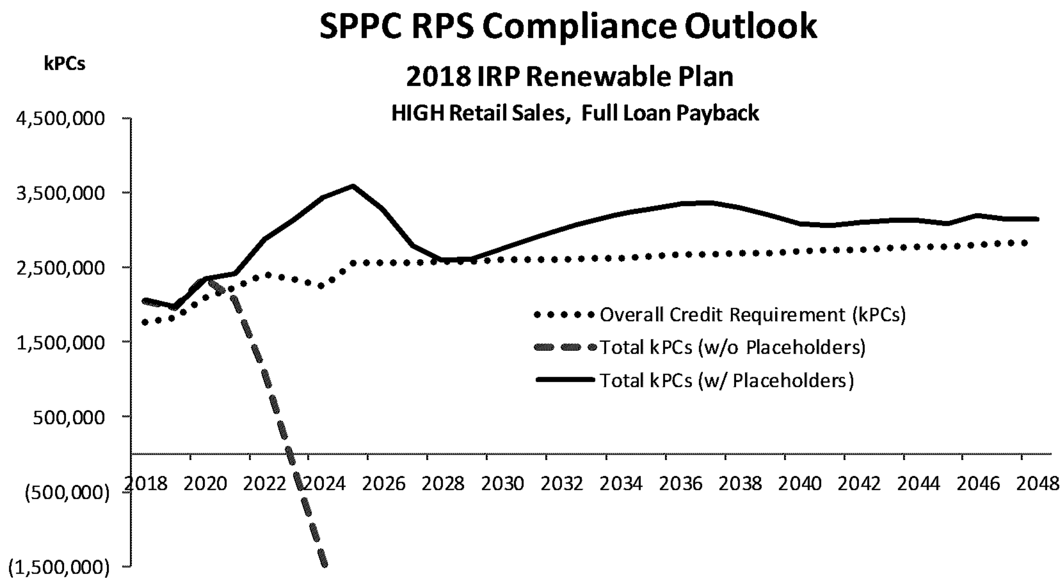
Projected RPS credit short-fall assuming no Placeholder Projects >> **2021**

		Project	MW	COD MTH/YR	
ER RFP	>	8minutenergy Eagle Shadow Mountain Solar	300.0	1	2022
ER RFP	>	Sempra 1.0 Copper Mountain 5	250.0	1	2022
ER RFP	>	174 Power Global 1 Techren V	50.0	1	2021
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2023 *
Placeholder	>	PPA PV SN 25 MW Tracking (2X)	50.0	1	2023 *
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2030
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2030
Placeholder	>	PPA PV SN 25 MW Tracking (2X)	50.0	1	2030
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2031
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2031
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2032
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2032
Placeholder	>	PPA PV SN 25 MW Tracking (2X)	50.0	1	2032
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder	>	PPA Geo NN 25 MW (2X)	50.0	1	2035
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2044
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2048
Placeholder	>	PPA PV SN 25 MW Tracking (4X)	100.0	1	2048
		Total NPC	2,100.0		

* additional capacity that is needed t double total operating capacity by 2023

The above placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

FIGURE REN-9
SIERRA'S RPS OUTLOOK
THREE PPAS PLUS 150 MW, HIGH RETAIL SALES



Projected RPS credit short-fall assuming no Placeholder Projects >> **2021**

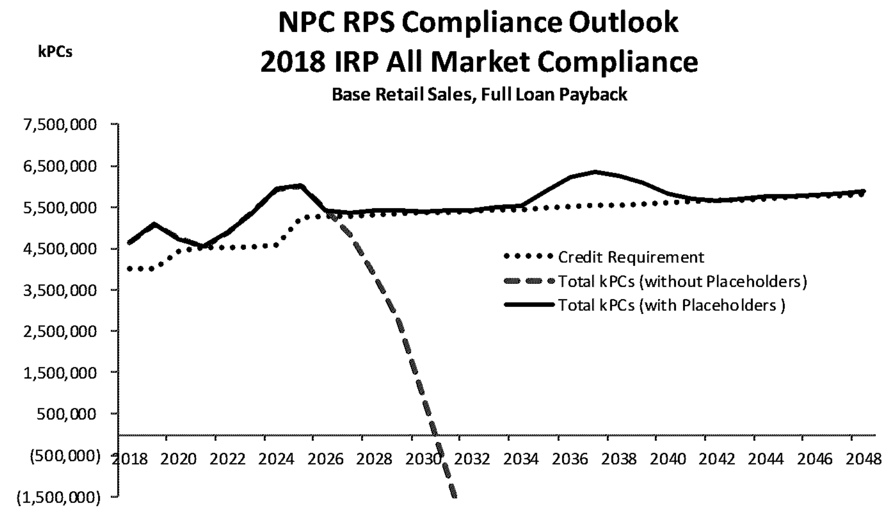
		Project	MW	COD MTH/YR	
ER RFP	>	NextEra 1.0 Dodge Flat	200.0	9	2021
ER RFP	>	NextEra 3.0 Fish Springs Ranch Solar	100.0	12	2021
ER RFP	>	Cypress Creek 1.0 Battle Mountain	101.0	6	2021
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2022 *
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2023 *
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2028
Placeholder	>	PPA PV NN 25 MW Tracking (1X)	25.0	1	2028
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2029
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2029
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2030
Placeholder	>	PPA PV NN 25 MW Tracking (2X)	50.0	1	2041
Placeholder	>	PPA PV NN 25 MW Tracking (1X)	25.0	1	2042
Placeholder	>	PPA PV NN 25 MW Tracking (3X)	75.0	1	2046
Placeholder	>	PPA Geo NN 25 MW (2X)	50.0	1	2047
Placeholder	>	PPA PV NN 25 MW Tracking (4X)	100.0	1	2047
Total SPPC		Total	1,176.0		

* additional capacity that is needed t double total operating capacity by 2023

The above placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

In addition to modeling the Low Carbon Case and the Renewable Case, the Companies also modeled an alternative, minimal compliance plan as shown in Figures REN-10 and REN-11. Unlike the Low Carbon Case and the Renewable Case, the Market Case assumes that each company will only add the minimal amount of new renewable capacity and associated PCs required to maintain RPS compliance. Nevada Power, assuming Crescent Dune is able to successfully cure it operating issues, should be compliant through 2027 without adding new renewable capacity. Sierra will require the approval of at least one project otherwise it will be non-compliant starting in 2022. One market case assumes that Sierra receives Commission approval to enter into a single agreement, the 8minutenergy Eagle Shadow Mountain Solar project. It is important to note that approval of this one project will only extend Sierra's projected RPS compliance by a single year. Sierra will still need to seek Commission approval for an additional 25 MW resource, assuming a solar PV project, in a later filing if Sierra is to remain compliant past 2022.

FIGURE REN-10
NEVADA POWER MINIMUM NEW RESOURCES REQUIRED TO MAINTAIN COMPLIANCE, BASE RETAIL SALES

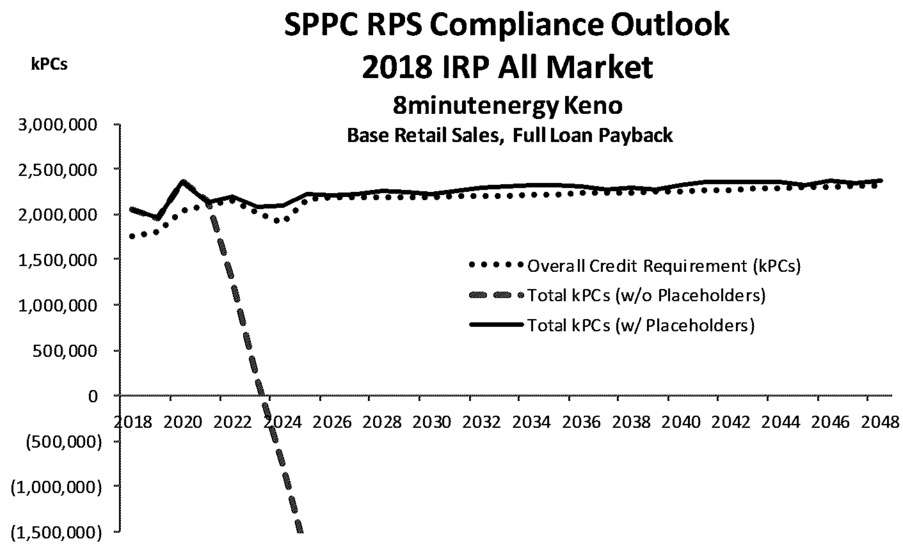


Projected RPS credit short-fall assuming no Placeholder Projects >> **2027**

	Project	MW	COD MTH/YR	
ER RFP >	NA	0.0		
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2027
Placeholder >	PPA PV SN 25 MW Tracking (3X)	75.0	1	2027
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2028
Placeholder >	PPA PV SN 25 MW Tracking (3X)	75.0	1	2028
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2030
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2030
Placeholder >	PPA PV SN 25 MW Tracking (2X)	50.0	1	2030
Placeholder >	PPA PV SN 25 MW Tracking (1X)	25.0	1	2031
Placeholder >	PPA PV SN 25 MW Tracking (1X)	25.0	1	2032
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2033
Placeholder >	PPA PV SN 25 MW Tracking (3X)	75.0	1	2033
Placeholder >	PPA Geo NN 25 MW (2X)	50.0	1	2035
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2041
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2041
Placeholder >	PPA PV SN 25 MW Tracking (1X)	25.0	1	2041
Placeholder >	PPA PV SN 25 MW Tracking (2X)	50.0	1	2042
Placeholder >	PPA PV SN 25 MW Tracking (1X)	25.0	1	2043
Placeholder >	PPA PV SN 25 MW Tracking (4X)	100.0	1	2044
Placeholder >	PPA PV SN 25 MW Tracking (1X)	25.0	1	2046
Placeholder >	PPA PV SN 25 MW Tracking (1X)	25.0	1	2047
	Total NPC	1,625.0		

The above placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

FIGURE REN-11
SIERRA'S MINIMUM NEW RESOURCES REQUIRED TO MAINTAIN COMPLIANCE, BASE RETAIL SALES



Projected RPS credit short-fall assuming no Placeholder Projects >> **2022**

	Project	MW	COD MTH	/YR
ER RFP >	8minutenergy Eagle Shadow Mountain Solar	300.0	1	2022
Placeholder >	PPA PV NN 25 MW Tracking (1X)	25.0	1	2023
Placeholder >	PPA PV NN 25 MW Tracking (3X)	75.0	1	2025
Placeholder >	PPA PV NN 25 MW Tracking (4X)	100.0	1	2026
Placeholder >	PPA PV NN 25 MW Tracking (3X)	75.0	1	2027
Placeholder >	PPA PV NN 25 MW Tracking (1X)	25.0	1	2028
Placeholder >	PPA PV NN 25 MW Tracking (2X)	50.0	1	2029
Placeholder >	PPA PV NN 25 MW Tracking (1X)	25.0	1	2031
Placeholder >	PPA PV NN 25 MW Tracking (2X)	50.0	1	2038
Placeholder >	PPA PV NN 25 MW Tracking (1X)	25.0	1	2040
Placeholder >	PPA PV NN 25 MW Tracking (2X)	50.0	1	2046
Placeholder >	PPA Geo NN 25 MW (2X)	50.0	1	2047
Placeholder >	PPA PV NN 25 MW Tracking (4X)	100.0	1	2047
Placeholder >	PPA PV NN 25 MW Tracking (1X)	25.0	1	2047
Placeholder >	PPA PV NN 25 MW Tracking (2X)	50.0	1	2048
Total SPPC	Total	1,025.0		

The above placeholder projects do not imply intent. The timing and type of projects selected will be driven based on the proposals submitted and the options that are available at the time.

Nevada Power and Sierra will continue to closely monitor its RPS compliance outlook recognizing that there are a myriad of factors, many outside of the Companies' control, which ultimately determine whether the Companies will have a sufficient number of PCs to satisfy their RPS credit obligation. The objective is to never be put into a reactive position where the Companies must acquire a large number of PCs in a short time frame in order to maintain compliance. Time expands options which in turn increases the ability of the Companies to negotiate favorable contracts to acquire renewable generating resources to meet the needs of their customers and to all regulatory standards.

Technical Appendix REN 1-4 contain the placeholder profiles and placeholder pricing that were used to develop the above outlooks. The appendices also contains the 12x24 supply tables, and degradation for the six proposed projects as well tables showing the projected RPS credit requirement and a breakdown of total PCs by year for each of the above scenarios modeled.

4. JOINT 2018 RENEWABLE RFP

Sierra and Nevada Power issued the 2018 renewable energy request for proposals ("2018 Renewable RFP") on January 9, 2018, with the intent of Sierra securing proposals for the acquisition of long-term renewable energy resources ranging from 35 MW up to approximately 330 MW in size, together with all associated environmental and renewable energy attributes. The timing of the RFP was driven by Sierra's impending RPS short position. The RFP was renewable technology agnostic and included a request for optional battery energy storage systems ("battery storage").

The Companies have reached a point where they can be selective in choosing projects that not only meet future energy needs but also meet those needs at competitive prices. All of the Companies' renewable projects, both PPA and company-owned, are located in Nevada, and are currently delivering renewable energy to meet the needs of the Companies' customers. In this filing, the Companies are requesting Commission approval to enter into six new PPAs, three for Nevada Power totaling 600 MW and three PPAs for Sierra totaling 401 MW. All six PPAs are modeled in the Low Carbon Case and the Renewable Case. Approval of these PPAs is a significant step in helping the Companies to achieve a goal of doubling renewable energy by 2023. The addition of these cost-effective renewable energy projects, together with 100 MW of battery storage (with 400 MWh of energy delivery capability) is consistent with the Companies' strategy of delivering energy and services that customers value at low and reasonable rates. The addition of these resources furthers the transformation of the Companies' energy supply portfolio, reducing both carbon emissions and risk.

Similar to the approach set forth in the Emissions Reduction and Capacity Replacement plan, the Companies prepared and completed the RFP for new renewable energy projects in Nevada. The

Companies developed and implemented a process for this RFP consistent with guidance previously provided by the Commission Staff.

a. JOINT 2018 RENEWABLE RFP BID PROTOCOL

The Companies prepared a bid protocol ("Protocol") describing the purpose of the RFP, the process by which the RFP would be conducted, the schedule, a description of the information required for each bid, bid submittal instructions, minimum eligibility requirements, and a description of the evaluation process. Bidders were instructed to review and propose changes to a NV Energy-provided PPA, as well as a Build Transfer Agreement ("BTA"), an Asset Purchase Agreement ("APA") and associated Engineering, Procurement and Construction ("EPC") agreement pro-forma documents.

The Protocol required bidders to register in the Companies' PowerAdvocate system, a web-enabled tool used by the Companies' procurement group to manage competitive bidding processes. Bidders that registered in PowerAdvocate were provided the bid Protocol along with all the other documents and information necessary to prepare and submit their proposals.

All communication with bidders, up to commencement of negotiations, was conducted through PowerAdvocate. Using PowerAdvocate, bidders were able to submit questions to the Companies who then responded to bidders through PowerAdvocate. Bids were required to be submitted using the PowerAdvocate tool.

A bid fee was required for each bid submittal; $10,000 for projects with a nameplate capacity of 100 MW and greater, and $5,000 for projects with a nameplate capacity of 35 MW to 99 MW, which could include up two bid price structure alternatives. Up to three additional pricing variations could be proposed for an additional $1,000 fee each. Battery storage proposals were assessed an additional $5,000 bid fee. A total of $415,000 in fees was collected, $370,000 of which was retained by the Company, with the balance of $45,000 being returned to disqualified or overpaid bidders. The retained bid fees were used to help cover the cost of the Independent Evaluator ("IE") and other external consulting costs.

b. INDEPENDENT EVALUATOR

The Companies utilized the services of an IE for the RFP. The IE oversaw the RFP to ensure a competitive, fair and transparent RFP process was conducted. Use of the IE for this RFP event was not required however, in light of the parallel effort to bring forward Company-owned projects, the IE provided an additional level of oversight to ensure that the RFP process was not influenced by the efforts of the Company to propose competitive projects. The IE, among other things, validated that the RFP evaluation criteria, methods, models, and other processes were consistently and appropriately applied to all bids and that the assumptions, inputs, outputs and results were

appropriate and reasonable. The IE independently scored the bids to determine whether the Companies' initial or final selections were reasonable, and oversaw negotiations. The IE report of findings is contained in Confidential Technical Appendix REN-9.

c. 2018 Request for Proposals

The RFP was issued on January 9, 2018. The RFP Protocol document informed interested parties that NV Energy was seeking to acquire long-term renewable energy resources, and their associated environmental and renewable energy attributes, ranging from 35 MW up to approximately 330 MW in size. The RFP specifically asked for proposals necessary for Sierra to meet its continuing compliance obligations under the RPS: 35 MW of renewable resources by December 31, 2020 and an additional 295 MW by December 31, 2021. The Companies stated they would consider qualified proposals for existing or new renewable resources to be developed with a minimum net power production capacity of 35 MW. The Companies requested proposals from projects that qualified as renewable energy resources as defined under NRS §§ 704.7315, 704.7811 and 704.7815, and pursuant to NAC §§ 704.8831 through 704.8893, including, but not limited to, solar, geothermal, wind, and biomass. The Companies also stated that while the RFP was not renewable technology specific, they would not consider demand-side, energy efficiency, or Nevada portfolio energy credit-only proposals. In addition to renewable energy resources, the Companies stated they would consider supplemental battery storage associated with proposed renewable energy resources that are eligible for the Investment Tax Credit ("ITC"). The Companies specified that battery storage should be capable of delivering a minimum power output of 25 MW for four hours (total of 100 MWh).

Acceptable ownership structures for long-term renewable energy resources included PPAs, APAs for certain existing renewable energy resources, and BTAs. PPAs for renewable energy resources were required to be for 25 years in length, and include purchase options that allow NV Energy to purchase the renewable energy resource, including all energy, capacity and associated environmental and renewable energy attributes, at periodic intervals following the commercial operation date of the renewable energy resource, including at the end of the 25 year term. PPAs for battery storage systems were required to have a term of 10 years, with a cost option for a 5-year extension. APAs for the sale of existing renewable energy resources would be considered as long as the resource was not currently under contract with NV Energy. Any BTAs would also be considered, subject to NV Energy's EPC standards.

Scoring criteria for proposals set out by the Companies in the Protocol document included: (a) the greatest economic benefit to the State of Nevada, (b) the greatest opportunity for the creation of new jobs in the State of Nevada, (c) the best value to NV Energy's customers; and, (d) the financial stability of the bidder and the ability of the bidder to financially back the proposal and any warranties and production guarantees.

The Protocol document required projects to have a point of delivery already identified and connect directly to NV Energy's transmission system. The RFP Protocol and attachments are included in Technical Appendix REN-5.

Proposals were due February 2, 2018. The Companies received more than 100 conforming bids from 16 counter-parties, covering 22 project sites, totaling 3,774 MW of nameplate renewable energy resource capacity and 797 MW of supplemental battery energy storage. Nineteen projects were for solar PV technology, and one proposal each was submitted for wind, bio-power, and geothermal technologies, respectively. Of the 19 proposals involving solar technology, 16 included options for associated battery storage systems. Two stand-alone battery storage systems were proposed but due to their ineligibility for the ITC, they were disqualified as non-conforming. Additionally, two solar PV proposals were disqualified as non-conforming because they were not to be located in Nevada.

Table REN-1 provides a summary of the bid options allowed under the RFP and the number of conforming bids received for each option in response to the RFP.

TABLE REN-1
CONFORMING PROPOSALS RECEIVED FOR 2018 Renewable RFP

	Category:	**A**	**B**	**C**	
Product	**Bid Option**	**Renewable**	**Renewable + Storage**	**Storage Only**	**Total PV MW**
	Existing Generating Facility:				
1	PPA	0	0	0	0
2	APA	0	0	0	0
	New Storage at Existing NVE Contracted Renewable Energy Project:				
3	PPA	0	0	0	0
4	BTA	0	0	0	0
	New Project:				
5	PPA	36	32	0	3,774
6	BTA	4	2	0	818 *

* Also bid as PPA

d. INITIAL EVALUATION PROCESS.

In the initial evaluation phase, bids were ranked based on a combination of three criteria: price, non-price and economic benefits to the State of Nevada.

Price was measured by calculating the levelized cost of energy ("LCOE") over the term of the proposed PPA. The LCOE included projected energy payments under the PPA as well as the estimated cost of network upgrades for the proposed project. The LCOE accounted for any escalation of the bid price, as well as any degradation in energy deliveries over the term of the PPA, as indicated by the bidder in their bid submittal. The price score was given a 60 percent weight.

The non-price scoring was based on four categories: (1) the bidder's project development experience, (2) the technology of the project, (3) conformity to the pro-forma PPA and (4) project development milestones. The non-price score was given a 30 percent weight.

For the bidder's project development experience, the Companies evaluated the bidder's (a) project development experience, (b) Nevada, federal or tribal lands development experience, (c) ownership/operation and maintenance ("O&M") experience, (d) Occupational Safety and Health Administration recordable incident rate, and (e) financial capability. The bidder's project development experience accounted for 25 percent of the non-price score.

For technology of the project, the Companies evaluated the bidders' (a) technical feasibility, (b) resource quality, (c) bidder's equipment supply control, (d) utilization of the resource, (e) flexibility, (f) environmental benefits, (g) fuel diversity/hedging, and (h) other ancillary services. Technology of the projects accounted for 25 percent of the non-price score.

For conformity to the pro-forma agreements, the Companies evaluated the magnitude of the bidder's proposed edits to the proforma agreements. Conformity to the pro-forma agreements accounted for 25 percent of the non-price score.

For project development milestones, the Companies evaluated (a) land and environmental authorization status/feasibility, (b) water rights, (c) project financing status, (d) interconnection progress, (e) transmission requirements and (f) reasonableness of critical path dates. Project development milestones accounted for 25 percent of the non-price score.

The economic benefit to State of Nevada scoring was based on three categories: (1) location of jobs relative to the off-taking company (i.e., Sierra or Nevada Power); (2) number of jobs created during construction and for ongoing operation of the project; and (3) value of direct expenditures of the project in Nevada. The economic benefits score was given a 10 percent weight.

Based on the resulting weighted scores of the bids, initial shortlists for each resource type (i.e. solar, solar + storage, biopower, etc.) were developed. Table REN-2 provides a list of the bids for the 2018 Renewable RFP initial shortlist.

TABLE REN-2
2018 RENEWABLE RFP SHORTLIST

Bidder/ Project	Product	Offer COD (Contract Term)
8minutenergy Eagle Shadow Mountain Solar	Solar PV PPA	12/31/2021
Sempra Copper Mountain 5	Solar PV PPA	12/31/2021
174 Power Global Techren V	Solar PV PPA	12/31/2020
Cypress Creek Battle Mountain Solar	Solar PV PPA with Battery Storage	6/1/2021
NextEra Dodge Flat	Solar PV PPA with Battery Storage	12/1/2021
NextEra Fish Springs Ranch	Solar PV PPA with Battery Storage	12/1/2021
EnviroPower Renewable Las Vegas Apex Astra	Biopower	07/07/2020

Bidders selected for the 2018 Renewable RFP initial shortlist were notified on March 7, 2018, with the exception of 174 Power Global, which was notified on March 9, 2018. Shortlisted bidders were permitted to submit "best and final" pricing by March 12, 2018.

The initial shortlist selections were reviewed with the IE and the IE concurred with the Companies' selection.

d. PWRR ANALYSIS.

Bids selected for the initial shortlist in the 2018 Renewable RFP were evaluated using the Companies' PWRR analysis. Each bid was run through the Companies' production cost simulation model PROMOD, and capital expense recovery model ("CER") to determine the potential PWRR impacts that each bid would have on the Companies' customers. The total PWRR for each bid scenario was reported and ranked from lowest PWRR to highest PWRR.

PWRR Results. Table REN-3 shows the PWRR Results for the shortlisted bids. Annual production costs and the PWRR are found in Technical Appendix Items ECON-8.

TABLE REN-3
RENEWABLE PPA PWRR RESULTS
2018 RENEWABLE RFP

	10 Year PWRR 2018-2027 (million $)	20 Year PWRR 2018-2037 (million $)	30 Year PWRR 2018-2047 (million $)	10 Year PWRR Increase vs Least Cost (million $)	20 Year PWRR Increase vs Least Cost (million $)	30 Year PWRR Increase vs Least Cost (million $)
8_MINUTE	$ 10,660	$ 19,269	$ 24,794	$ -	$ -	$ -
Sempra	$ 10,664	$ 19,294	$ 24,840	$ 3	$ 25	$ 47
Cypress_BESS	$ 10,671	$ 19,298	$ 24,840	$ 11	$ 29	$ 46
Cypress_Creek	$ 10,672	$ 19,300	$ 24,842	$ 11	$ 30	$ 48
NextEra_Fish_Springs	$ 10,674	$ 19,305	$ 24,844	$ 14	$ 36	$ 51
Power_Global	$ 10,673	$ 19,306	$ 24,849	$ 13	$ 36	$ 56
Fish_BESS	$ 10,675	$ 19,306	$ 24,845	$ 15	$ 37	$ 52
Sempra_BESS	$ 10,676	$ 19,310	$ 24,856	$ 16	$ 41	$ 62
Nextera_Dodge_Flats	$ 10,681	$ 19,311	$ 24,847	$ 21	$ 41	$ 53
Dodge_BESS	$ 10,686	$ 19,314	$ 24,850	$ 25	$ 44	$ 56
EPRenewable	$ 10,791	$ 19,516	$ 25,102	$ 131	$ 247	$ 309

Key Result Findings. The following are the key results findings of the PWRR analysis:

- The 8minutenergy project is the largest project and has the lowest PWRR over the 30-year study period.
- The NextEra Projects, with battery storage added to their solar-only bids, result in slightly less customer benefit when modeled alone; however they may enable savings elsewhere when battery storage benefits are aggregated with the proposed portfolio of projects.

e. ADDITIONAL ANALYSIS OF SHORTLISTED BIDS

. Additional due diligence was conducted on the shortlisted bids. The due diligence included: (1) status and timing of interconnection, (2) site control, (3) status of material permits, (4) solar panels, (5) other material equipment, (6) delivery profile, (7) milestone schedule, (8) material exceptions to the pro-forma PPA, (9) development and operating experience, (10) financial capability, (11) safety, (12) water supply, and (13) project labor agreement. Burns & McDonnell was retained to evaluate items (4), (5), (6), (7) and (9) and internal subject matter experts evaluated the remaining items. Based on this analysis, the top bidder for negotiations was selected. No fatal flaws were identified with any of the shortlisted bids.

f. Final Selection

The final shortlist was completed on April 2, 2018. Six projects were selected from five counterparties.[25] Of the six projects selected, three are to be located in Sierra's service territory, and three are to be located in Nevada Power's service territory. All six projects will utilize PV panels with single axis trackers, and all three projects located in Sierra's service territory will include battery storage charged by the respective solar renewable resource. Five of the selected projects have nameplate solar capacity of 100 MW or greater, with the largest project featuring a 300 MW nameplate solar capacity. Battery storage systems will include two 25 MW storage capacity systems, and one 50 MW storage system, all dispatchable for four hours.

NextEra's Dodge Flat is a proposed 200 MW capacity solar facility with an associated 50 MW capacity battery storage system located on the same project site. Dodge Flat is located in Sierra's service territory, with an anticipated commercial operation date ("COD") of December 1, 2021. The solar component of the Dodge Flat project will contribute to fulfilling Sierra's RPS compliance obligation.

NextEra's Fish Springs Ranch is a proposed 100 MW capacity solar facility with an associated 25 MW capacity battery storage system collocated on the same project site. Fish Springs Ranch is located in Sierra's service territory, with an anticipated COD of December, 1, 2021. The solar component of the Fish Springs Ranch project will contribute to fulfilling Sierra's RPS compliance obligation.

Cypress Creek Renewables' Battle Mountain Solar is a proposed 101 MW capacity solar facility with an associated 25 MW capacity battery storage system located on the same project site. Battle Mountain Solar is located in Sierra's service territory, with an anticipated COD of June 1, 2021. The Battle Mountain Solar project will contribute to fulfilling Sierra's RPS compliance obligation.

8minutenergy's Eagle Shadow Mountain Solar is a proposed 300 MW capacity solar facility. It is located in Nevada Power's service territory on the Moapa Band of Paiutes Tribal land. It has an anticipated COD of December 31, 2021. The Eagle Shadow Mountain Solar near Moapa project will contribute to fulfilling Nevada Power RPS compliance obligation.

Sempra's Copper Mountain 5 is a proposed 250 MW capacity solar facility. It is located in Nevada Power's service territory, with an anticipated COD of December 31, 2021. The Copper Mountain 5 project will contribute to fulfilling Nevada Power's RPS compliance obligation.

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[25] Lower scoring projects were not brought forward in this filing due to insufficient time to conduct a comprehensive due diligence review and complete negotiations in time to meet this filing date. As such, the Companies did not commence negotiations with additional parties.

174 Power Global's Techren V is a proposed 50 MW capacity solar facility with a commercial operation date of December 31, 2020. Techren V will be located adjacent to Techren I, Techren II, Techren III and Techren IV which are all contracted to NV Energy. The Techren V project will contribute to fulfilling Nevada Power's RPS compliance obligation.

Once again, project scoring, ranking and selection were reviewed with the IE, and once again, the IE concurred with the Companies' selections. The Companies' documentation of the final analysis and selections is contained in Confidential Technical Appendix REN-8.

The Companies successfully completed negotiations with the bidders for the portfolio of projects comprising the Preferred Plan and executed the agreements on May 14, 2018.

5. APPROVAL OF SIX NEW RENEWABLE PPAS

Six PPAs are being submitted to the Commission for approval. Three of the PPAs include battery storage with a per-megawatt-month capacity payment in addition to the usual per-megawatt-hour payment for energy. These supply additions, described below, support continued compliance with the RPS, contribute to managing the open position, enhance fuel diversity, and leverage the reactive power capabilities of solar PV and energy storage inverters to provide voltage support to the grid. With these projects, the Companies lock in a substantial level of renewable energy supply at the current market's attractive pricing for the long-term benefit of its customers, before the ITC expires.

All six PPAs and the three battery storage systems are incorporated into the Low Carbon Case and the Renewable Case. The Low Carbon Case has been selected as the Companies' Preferred Plan, in the event Question 3 is not approved by voters in November 2018. The Renewable Case has been selected as the Companies' alternative plan, again in the event that voters do not approve Question 3 in November 2018. If the voters approve Question 3, the Companies recommend that the Commission approve the short-term Question 3 alternative case. This case involves the addition of a single renewable resource, the lowest cost PPA from the 2018 Renewable RFP, which was executed with 8minutenergy. That resource also has lower network upgrade costs, thus minimizing total costs in short-run. This case does not provide the same economic development and environmental benefits as the Low Carbon Case, but provides the best option in a short-run planning scenario.

The Companies request that the Commission's order reflect the statutory consequence of such a finding; namely, that the PPA contracts and their terms shall be deemed to be prudent investments and the utility provider may recover all just and reasonable costs associated with the contracts pursuant to NRS § 704.7821(2)(c)(2). Table REN-4 summarizes the new contracts completed and filed for Commission approval in this filing.

TABLE REN-4
NEW CONTRACTS

Counterparty	Agreement Type	Technology	Capacity	Expected Commercial Operation
8minutenergy Eagle Shadow Mountain Solar	PPA	PV	300 MW	12/31/2021
Sempra Copper Mountain 5	PPA	PV	250 MW	12/31/2021
174 Power Global Techren V	PPA	PV	50 MW	12/31/2020
Cypress Creek Battle Mountain Solar	PPA	PV with Battery Storage	101 MW PV 25 MW Battery Storage	6/1/2021
NextEra Dodge Flat	PPA	PV with Battery Storage	200 MW PV 50 MW Battery Storage	12/1/2021
NextEra Fish Springs Ranch	PPA	PV with Battery Storage	100 MW PV 25 MW Battery Storage	12/1/2021

a. DODGE FLAT 200 MW SOLAR WITH 50 MW BATTERY STORAGE PPA (SIERRA)

The proposed project is a 200 MW solar PV facility to be developed by NextEra Energy Resources Acquisitions, LLC[26] near the community of Wadsworth, in Washoe County, Nevada. This project is largest solar PV facility proposed by Sierra in northern Nevada. NextEra Energy Resources Acquisitions, LLC is an indirect wholly-owned subsidiary of NextEra Energy Resources ("NEER"), which is part of the NextEra Energy, Inc. ownership structure. NextEra Energy, Inc. is a publicly traded Fortune 200 company with approximately $91.2 billion in total assets, owning some 45,900 MW of generating capacity, and employing 14,700 employees in 30 states and Canada, as of year-end 2016. NextEra Energy was incorporated in 1984, and conducts operations principally through two wholly-owned subsidiaries – Florida Power and Light Company ("FPL"), a regulated public utility, and NEER. NextEra Energy Capital Holdings, Inc. ("NEECH"), another wholly-owned subsidiary of NextEra Energy, owns and provides funding for NEER's and NextEra Energy's other operating subsidiaries, other than FPL and its subsidiaries.

[26] The PPA signatory is Dodge Flat Solar, LLC.

NEER is a competitive energy business whose primary business objective is the development, construction and operation of power plants. The company states that it has been generating clean energy for more than 25 years, and is the largest generator of wind and solar power in North America, with approximately 14,000 MW of wind, 2,600 MW of solar, and 100 MW of battery storage commercially operating in its portfolio as of 2016. All of NEERs solar projects are under long-term PPAs with utilities and commercial customers, and utilize PV solar modules and technology similar to those proposed as part of the Dodge Flat project.

The Dodge Flat project will consist of a 200 MW solar PV facility with a horizontal single-axis tracking mounting system. The project is sited on private land approximately 25 miles northeast of Reno, Nevada, near the town of Wadsworth. The Dodge Flat project will utilize Hanwha Q-Cells 425 W multi-crystalline PV modules, mounted on various tracking and fixed mounting systems with GE inverters. The DC energy generated by the panels will be wired to combiner boxes, then to inverters which convert the DC energy to AC energy. The AC energy will be routed to either a step-up transformer, where it will be delivered to the proposed Olinghouse 345 kV substation via a 250 foot long generation intertie, or to another set of inverters to charge the battery storage. As a dispatchable resource the battery storage will deliver its stored energy back through the inverters to the delivery point.

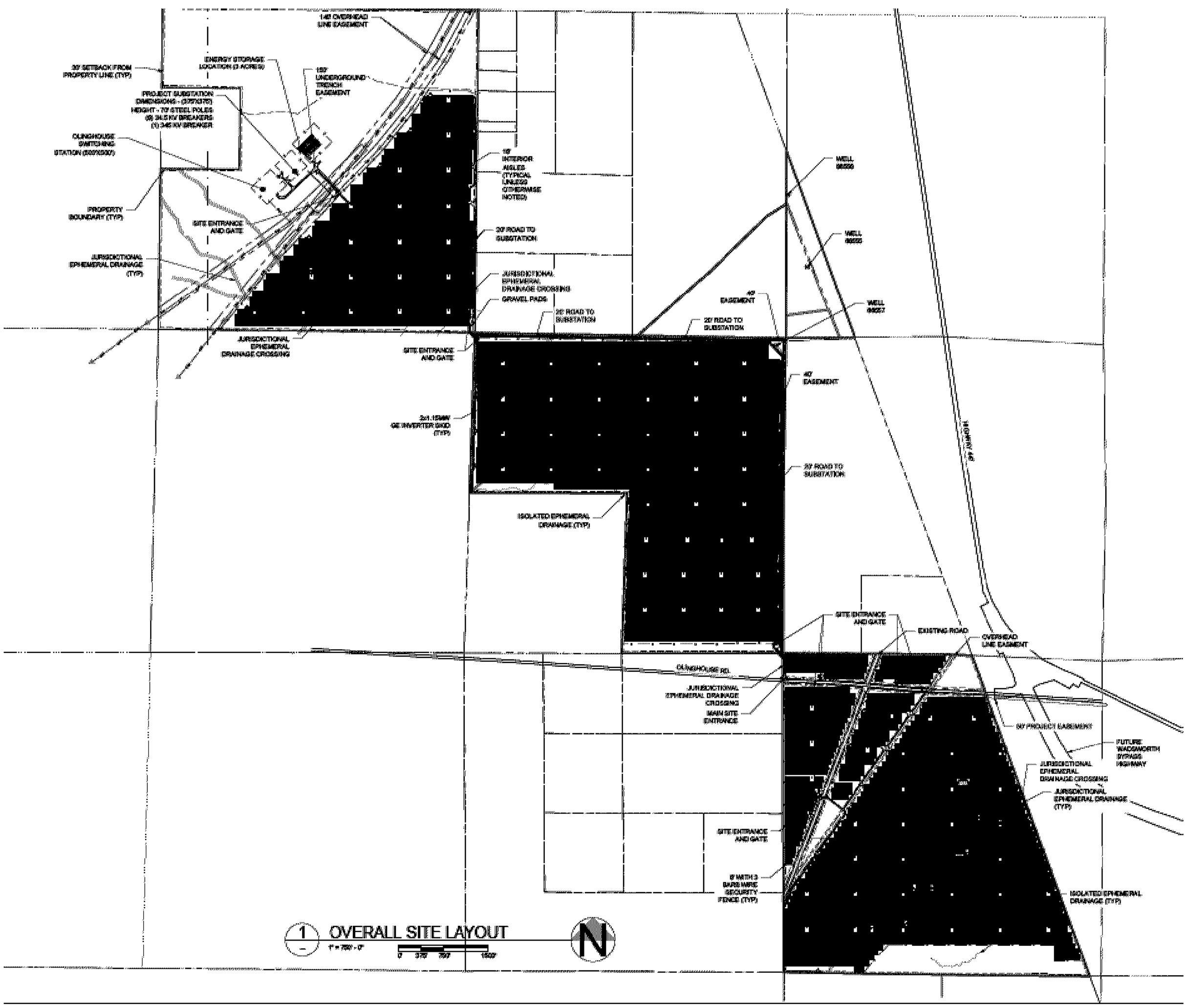
NextEra Energy Resource Acquisitions, LLC estimates that the Dodge Flat project will provide 339 construction jobs over a 1-year construction period. After commercial operation in December, 2021, the Dodge Flat facility is expected to provide 37 permanent jobs with an average annual salary of $45,760, for a total estimated annual payroll of $1,693,120 and a total payroll of $60 million over the life of the project. Overall, the Companies estimate that the total investment in Nevada's economy directly associated with the Dodge Flat project will be $467 million. A work site agreement, dated April 30, 2018, was successfully executed between Blattner Energy, Inc. on behalf of Dodge Flat and IBEW Local Union 401.[27]

The PPA is with Sierra for a 25-year term with a flat price of $27.51 per MWh ($26.51 per MWh if NextEra's proposed Fish Springs Ranch, discussed below, is also approved). The project has an expected net capacity rating of 200 MW (ac). It is expected to generate 574,307 MWh and provide 574,307 kPCs in the first year. Annual energy production and credits are projected to degrade at approximately one-half percent per year. The 50 MW, 200 MWh battery storage capacity payment is $6,110 per MW-month, escalating at 2 percent annually, for a contract term of 15 years. The PPA includes options for Sierra to purchase the asset at periodic intervals after commercial operation and at the end of the term. The purchase price for the option, prior to end of term, would be at the greater of (i) fair market value and (ii) the amount of any outstanding indebtedness owed to supplier's lenders pursuant to any financing or refinancing at the time of the closing of such

[27] NextEra has asked that the site agreement, which is set forth in the Dodge Flat PPA as Exhibit 21, remain confidential.

transaction, and at fair market value at end of term. A copy of the PPA can be found in Technical Appendix REN-6-DFS(a). Figure REN-12 shows a map of the project site.

FIGURE REN-12
NEXTERA DODGE FLAT PROJECT SITE



Technical Appendix REN-6-DFS (b) contains detailed information about the Dodge Flat Solar project, including the information required by NAC § 704.8885 and NAC § 704.8887.

b. FISH SPRINGS RANCH (SIERRA)

The proposed project is an additional 100 MW solar PV facility with a 25 MW battery to be developed by NextEra near Pyramid Lake, in Washoe County, Nevada.

The Fish Springs Ranch solar project consists of a 100 MW solar PV facility with a horizontal single-axis tracking mounting system. The project is sited on private land approximately 40 miles northeast of Reno, Nevada. Fish Springs Ranch will utilize Hanwha Q-Cells 425 W multi-

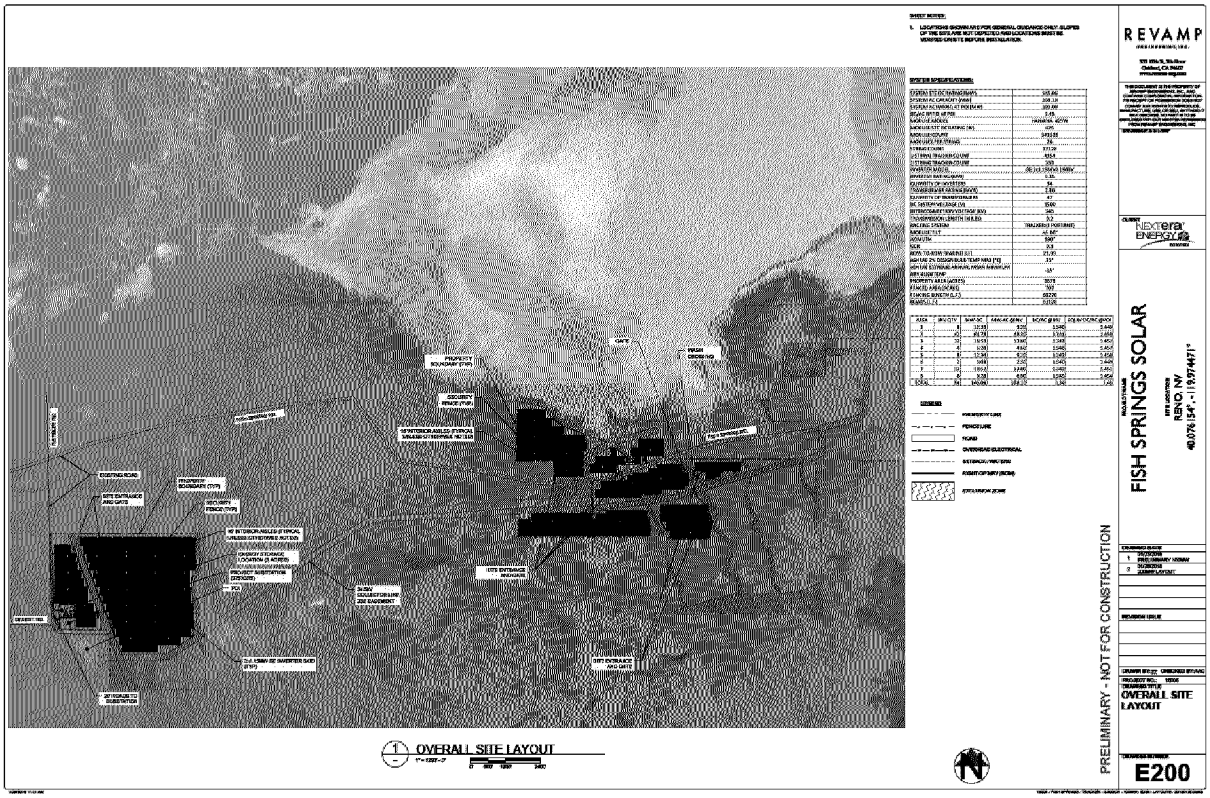
crystalline PV modules, mounted on various tracking and fixed mounting systems with GE inverters. The DC energy generated by the panels will be wired to combiner boxes, then to inverters which convert the DC energy to AC energy. The AC energy will be routed to a step-up transformer where it will be delivered to the Ft. Sage 345 kV substation. When dispatched, the battery storage will deliver its stored energy back through the inverters to the delivery point.

NextEra Energy Resource Acquisitions, LLC estimates that the Fish Springs Ranch project will provide 176 construction jobs over a 1-year period during construction. After commercial operation in December, 2021, the Fish Springs Ranch facility is expected to provide 19 permanent jobs with an average annual salary of $45,760, for a total estimated annual payroll of $869,440 and a total payroll of $31 million over the life of the project. Overall, NV Energy estimates that the total investment in Nevada's economy directly associated with the Fish Springs Ranch Solar project will be $234 million. A work site agreement, dated May 10, 2018, was successfully executed between Blattner Energy, Inc. on behalf of Fish Springs Ranch and IBEW Local Union 401.[28]

The PPA is with Sierra for a 25-year term with a flat price of $29.96 per MWh for PV. The project has an expected net capacity rating of 100 MW (AC). It is expected to generate 270,632 MWh and provide 270,632 kPCs in the first year. Annual energy production and credits are projected to degrade at approximately one-half percent per year. The 25 MW, 100 MWh battery storage capacity payment is $6,200 per MW-month, escalating at 2 percent annually, for a contract term of 15 years. The PPA includes options for Sierra to purchase the asset at periodic intervals after commercial operation and at the end of the term. The purchase price for the option, prior to end of term, would be at the greater of (i) fair market value and (ii) the amount of any outstanding indebtedness owed to supplier's lenders pursuant to any financing or refinancing of the facility at the time of the closing of such transaction, and at fair market value at end of term. A copy of the PPA can be found in Technical Appendix REN-6-FSR (a). Figure REN-13 shows a map of the project site.

[28] NextEra has asked that the site agreement, which is set forth in the Dodge Flat PPA as Exhibit 21, remain confidential.

FIGURE REN-13
FISH SPRINGS RANCH – PROJECT SITE



Technical Appendix REN-6-FSR(b) contains detailed information about the Fish Springs Ranch project, including the information required by NAC 704.8885 and NAC 704.8887.

c. Battle Mountain Solar (Sierra)

Battle Mountain 101 MW Solar PPA with a 25 MW, 100 MWh battery storage. The proposed project is a 101 MW solar PV facility with 100 MWh (25 MW x 4 hours) energy storage system to be developed by Cypress Creek Renewables near the City of Battle Mountain, in Humboldt County, Nevada. Cypress Creek Renewables is a wholly-owned subsidiary of Cypress Creek Holdings, LLC, which is a privately-held company. Cypress Creek Holdings, LLC, reported approximately $1.6 billion in total assets in 2016.

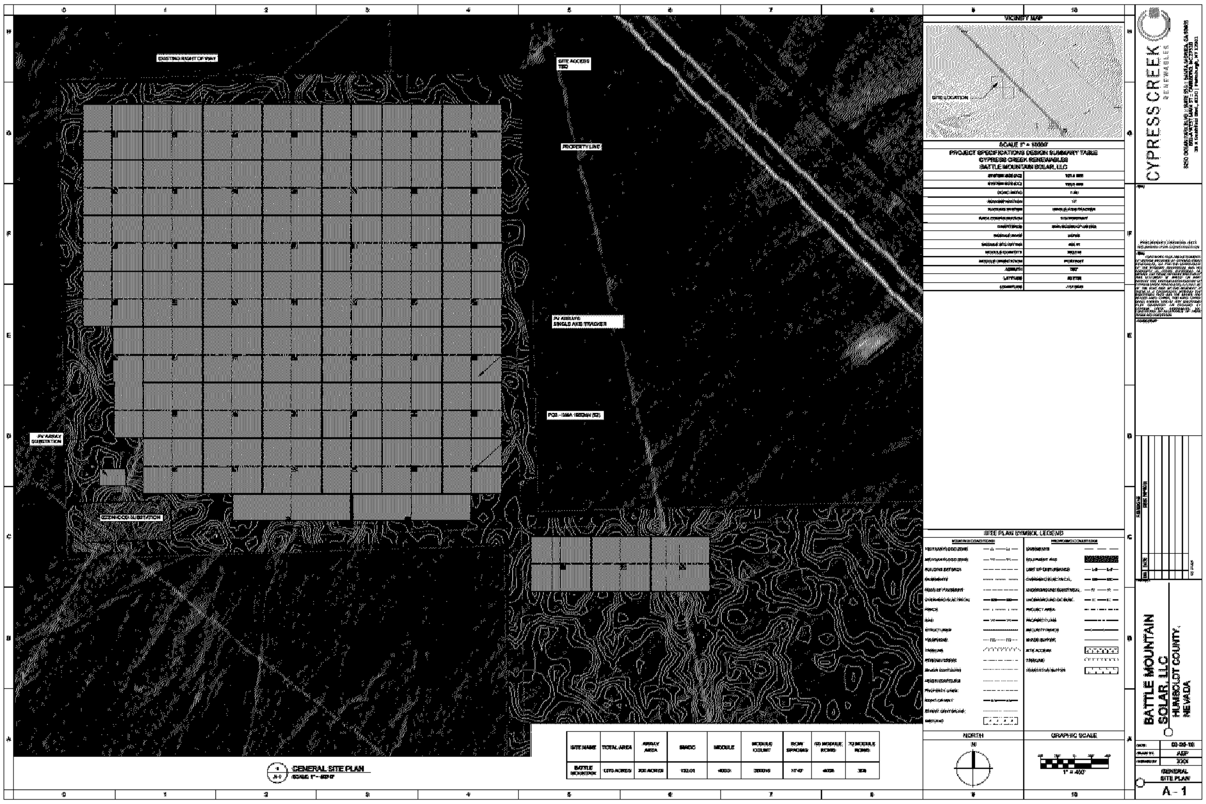
Cypress Creek Renewables states that it develops, finances, constructs, owns and operates solar energy projects through the United States. The company was founded in 2014 and has grown to be one of the largest solar development firms in the country, having successfully deployed more than 1,500 MW (ac) of solar projects to date, of which 1,000 MW are owned and operated by Cypress Creek. The remaining 500 MW have been sold to strategic counterparties such as Southern Company and Dominion.

Battle Mountain Solar consists of a 101 MW solar PV facility with a tracking mounting system as well as Lithium-Ion batteries manufactured by IHI for the energy storage. The project is sited on private land approximately 8.5 miles northwest of Battle Mountain, Nevada. The Battle Mountain project will utilize LONGi 400 W crystalline silicon PV modules, mounted on various Single-Axis Tracking systems manufactured by NEXTracker and using SMA or EPC Power inverters. The DC energy generated by the panels will be wired to combiner boxes, then to inverters which convert the DC energy to AC energy. The AC energy will be routed to a step-up transformer where it will be delivered to the proposed Izzenhood 120 kV switching station and through that substation approximately 2,000 feet to Sierra's 120 kV Battle Mountain – Valmy #120 transmission line. The battery storage system can be dispatched to deliver its stored energy back through the inverters to the delivery point.

Cypress Creek Renewables estimates that the Battle Mountain Solar project will provide 305 construction jobs over a 1-year period during construction. After commercial operation in June, 2021, the Battle Mountain Solar facility is expected to provide 3.5 permanent jobs with an average annual salary of $46,222 for a total estimated annual payroll of $161,777 and a total estimate payroll of $5 million over the 25-year life of the project. Overall, NV Energy estimates that the total investment in Nevada's economy directly associated with the Battle Mountain Solar project will be $210 million. A work site agreement, dated May 1, 2018, was successfully executed between Cypress Creek EPC, LLC and IBEW Local Unions 401 and 1245.

The PPA is with Sierra for a 25-year term with a flat price of $26.50 per MWh for energy. The project has an expected net capacity rating of 101 MW (ac). It is expected to generate 296,655 MWh and provide 296,655 kPCs in the first year. Annual energy production and credits are projected to degrade at approximately four-tenths percent per year. The 25 MW, 100 MWh battery storage capacity payment is $7,755 per MW-month with no escalation, for a contract term of 10 years. The PPA includes options for Sierra to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-6-BMS (a). Figure REN-14 shows a map of the project site.

FIGURE REN-14
BATTLE MOUNTAIN SOLAR – PROJECT SITE



Technical Appendix REN-6-BMS (b) contains detailed information about the Battle Mountain Solar project, including the information required by NAC 704.8885 and NAC 704.8887.

d. EAGLE SHADOW MOUNTAIN SOLAR FARM 300 MW SOLAR PPA (NEVADA POWER)

The proposed project is a 300 MW solar PV facility to be developed by 8minutenergy Renewables, LLC ("8minutenergy") within the Moapa River Indian Reservation in Clark County, Nevada. 8minutenergy had total assets of approximately $143 million and showed revenues of just over $2 million in 2016. 8minutenergy has received financing for approximately 37 comparable utility scale solar projects within the past 3 years.

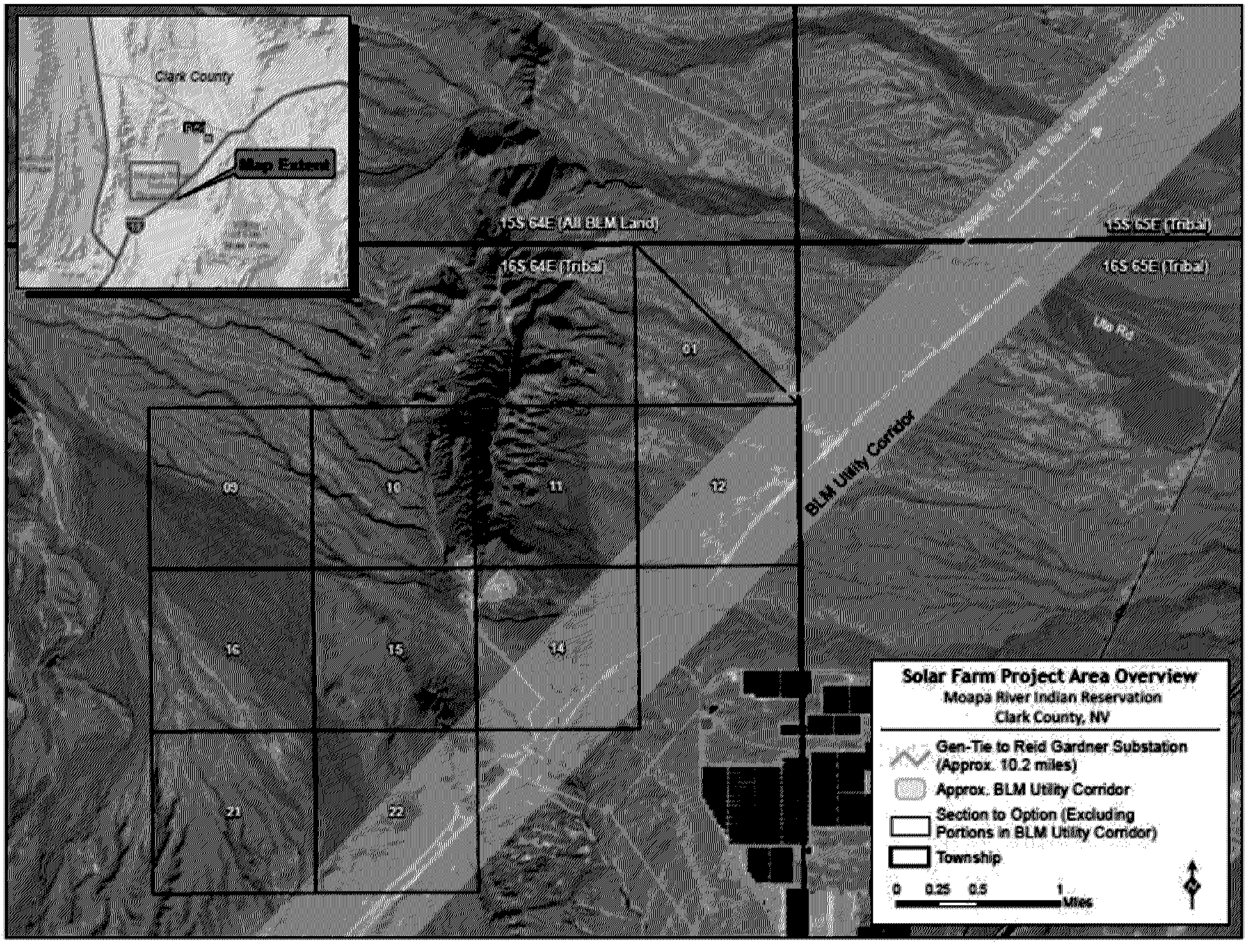
8minutenergy is the largest independent utility scale solar PV and energy storage developer in the US. Since inception in 2009, the company has developed and signed PPAs on over 1,500 MW of Solar PV projects. Key completed and operating projects in the portfolio include approximately 559 MW in California. 8minutenergy also has over 600 MW of solar projects under construction or construction ready.

Eagle Shadow Mountain Solar Farm (formerly Keno Solar Farm) consists of a 300 MW PV facility with a tracking mounting system. The project is sited on leased land from the Moapa Band of Paiute Indians and located in Clark County, Nevada. 8minutenergy, who is technology agnostic, intends to utilize a combination of solar PV panels, DC to AC inverters, single axis trackers plus associated electrical equipment like transformers and switchgears for the project.

8minutenergy estimates that the Eagle Shadow Mountain Solar Farm will provide 500 jobs over a 2-year period during construction. After commercial operation on December 31, 2021, the Eagle Shadow Mountain Solar Farm is expected to provide 7 permanent jobs with an average annual salary of $83,200, for a total estimated payroll of $71 million over 25 years. Overall, NV Energy estimates that the total investment in Nevada's economy directly associated with the Eagle Shadow Mountain Solar Farm will be over $741 million. A work site agreement, dated May 1, 2018, was successfully executed between 325MK 8me LLC and IBEW Local Union 357.

The PPA is for a 25 year term with a flat price of $23.76 per MWh. The project has an expected net capacity rating of 300 MW (ac). It is expected to generate 922,909 MWh and provide 922,909 thousand production credits ("kPCs") in the first year. Annual energy production and credits are projected to degrade at approximately three-tenths percent (0.3%) per year. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-6-ESM (a). Figure REN-15 shows a map of the project site.

FIGURE REN-15
EAGLE SHADOW MOUNTAIN SOLAR – PROJECT SITE



Technical Appendix REN-6-ESM (b) contains detailed information about the Eagle Shadow Mountain Solar project, including the information required by NAC 704.8885 and NAC 704.8887.

e. COPPER MOUNTAIN SOLAR 5 250 MW SOLAR PPA (NEVADA POWER)

The proposed project is a 250 MW PV facility to be developed by Sempra Renewables near the city of Boulder City, Nevada. Sempra Renewables is a subsidiary of Sempra Energy, a Fortune 300 energy services holding company. Sempra Energy had 2016 revenues of $10 billion. Its sister companies include San Diego Gas & Electric (SDG&E), Southern California Gas Company (SoCalGas) and Sempra International. Sempra Energy has over 16,000 employees serving more than 32 million consumers worldwide.

Sempra Renewables is a leading developer of solar and wind energy throughout the United States. It. As a renewable energy leader, Sempra Renewables has over 3,000 MW of solar, wind and

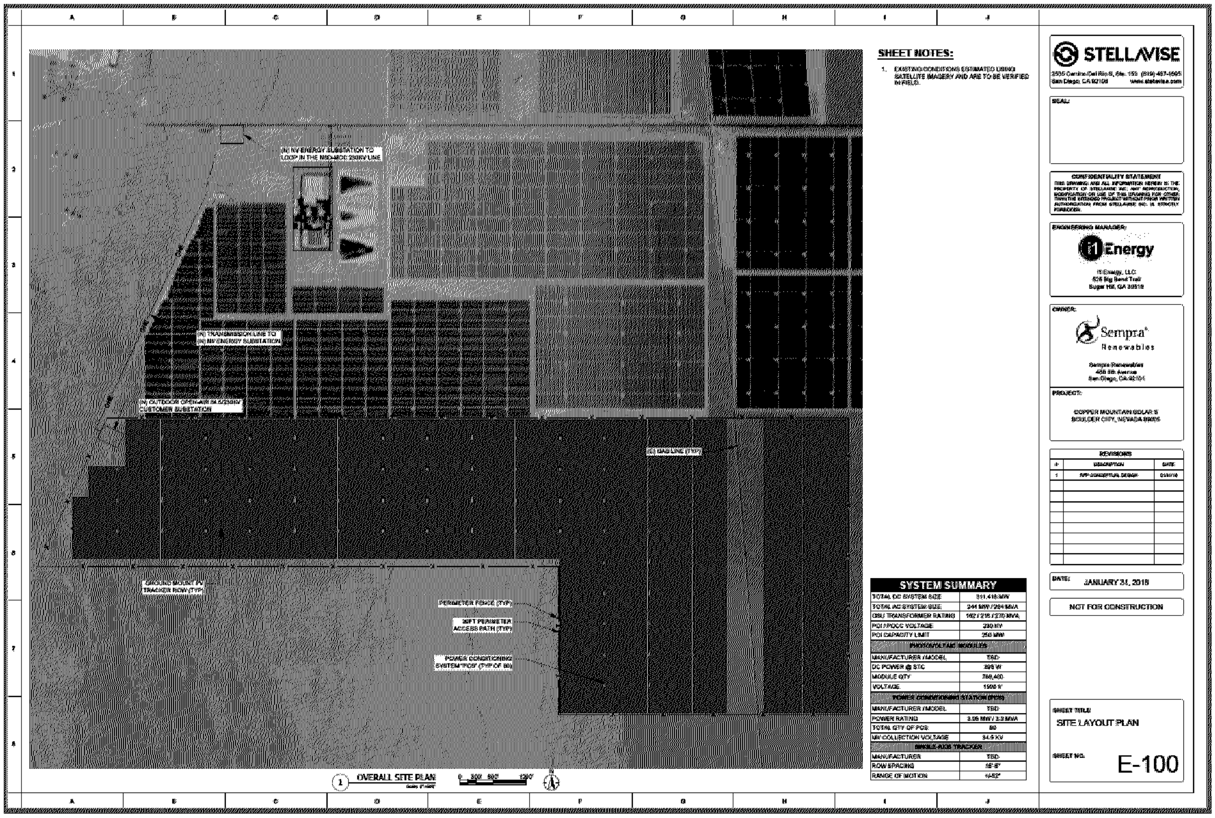
battery energy storage in operation and under development and construction. Copper Mountain Solar 5 ("CMS5") is a new development project and will be the fifth phase to Sempra Renewables' Copper Mountain Solar Complex, which currently consists of 4 operating projects with total combined capacities of over 550 MW.

CMS5 consists of a 250 MW PV facility with a tracking mounting system. The project is sited on leased land owned by Boulder City, Nevada and located near the City of Boulder City, Nevada, approximately 18 miles south of the city of Henderson, Nevada. This project site is located approximately 14 miles south of the intersection of Highway 93 and Highway 95 and is located to the west of Highway 95. The system will consist of PV panels mounted on single axis tracking steel structures, an electrical collection system that aggregates the output from the PV panels and converts the electricity form direct current ("DC") to alternating current ("AC"), as well as a solar substation where all of the facility output is combined and transformed through a step-up transformer to 230 kV to be transmitted to the Nevada Solar One (NSO) substation, approximately 1.2 miles from the project substation. All equipment used will be from Tier 1 Manufacturers per the approved NVE Vendors list.

Sempra Renewables estimates that the Copper Mountain Solar 5 will provide 375 jobs over a 2-year period during construction. After commercial operation on December 31, 2021, the Copper Mountain Solar 5 is expected to provide 5 permanent jobs with an average annual salary of $58,240, for a total estimated payroll of $17 million over 25 years. Overall, NV Energy estimates that the total investment in Nevada's economy directly associated with the Copper Mountain Solar 5 will be almost $584 million. A work site agreement, dated May 11, 2018, was successfully executed between Copper Mountain Solar 5, LLC and IBEW Local Unions 357 and 396, and Laborer's Union 872.

The PPA is for a 25 year term with a base price of $21.55 per MWh, with 2.5% annual escalation. The project has an expected net capacity rating of 250 MW (AC). It is expected to generate 720,222 MWh and provide 720,222 thousand production credits ("kPCs") in the first year. Annual energy production and credits are projected to degrade at approximately one-half percent (0.5%) per year. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-6-CMS5 (a). Figure REN-16 shows a map of the project site.

FIGURE REN-16
COPPER MOUNTAIN SOLAR 5 – PROJECT SITE



Technical Appendix REN-6-CMS5 (b) contains detailed information about the Copper Mountain Solar 5 project, including the information required by NAC 704.8885 and NAC 704.8887.

f. TECHREN SOLAR V 50 MW SOLAR PPA

The proposed project is a 50 MW solar PV facility to be developed by 174 Power Global ("174PG") in the city of Boulder City, Nevada. 174PG is a wholly owned subsidiary of the Hanwha Group through Hanwha Energy Corporation ("Hanwha Energy") and is responsible for Hanwha Group's solar development activities in the Americas. Hanwha Corporation was ranked 246th of the Fortune Global 500 list in 2017, with annual revenues of $41 billion, total assets of $128 billion and employing over 49,000 worldwide. Hanwha Corporation subsidiaries include Hanwha SolarOne and Hanwha Q CELLS ("HQC"), which, after a merger in 2015 is now the largest manufacturer of solar cells with a capacity of 5.2 gigawatts per year.

174PG is a fully integrated solar plant solutions provider with services in development, financing, engineering, procurement, construction, power plant ownership, operation and maintenance. While 174PG is a development company owned by Hanwha Energy and has some independence from its parent and sister companies, it has access to all the resources, expertise and experience of

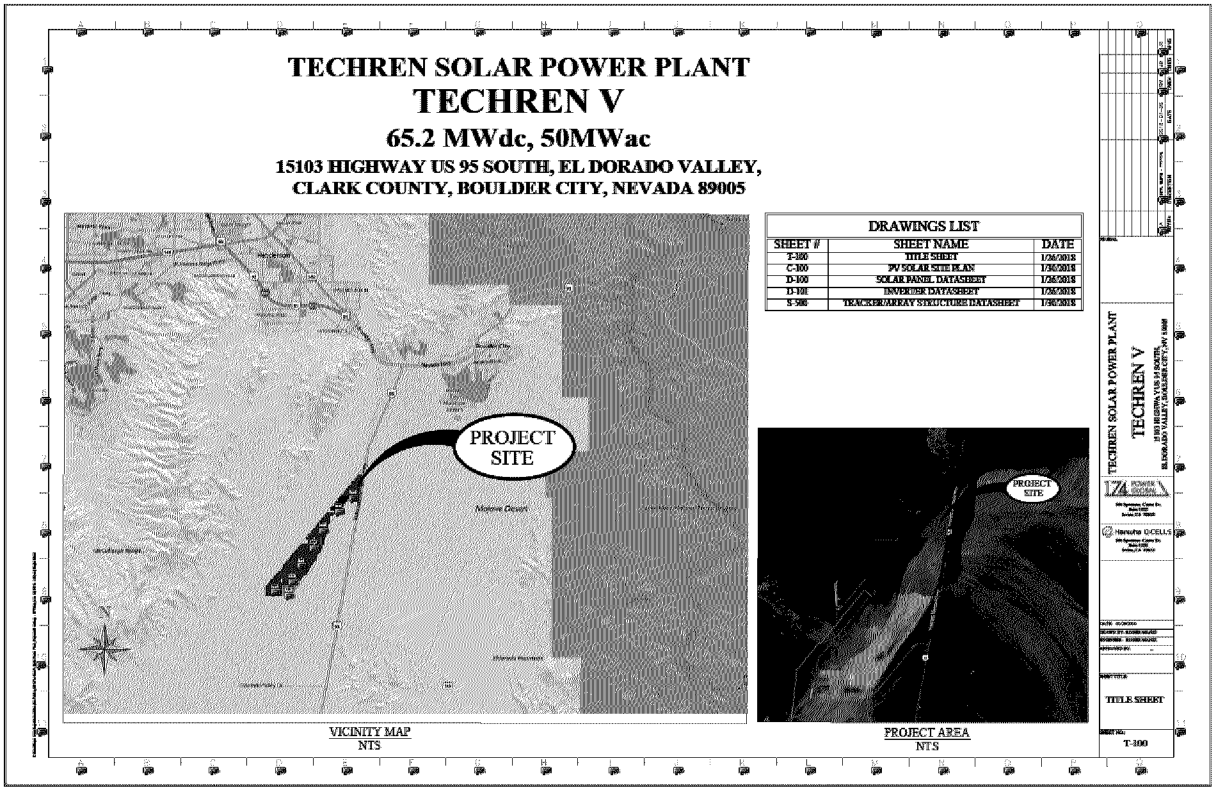
the collective group. Over the course of the last 4 years, the Hanwha group has developed and constructed 23 large scale PV projects ranging in sizes from 1 MW dc to 200 MW ac. These projects include 350 MW ac from Techren phases I, II, III and IV.

Techren Solar V consists of a 50 MW PV facility with a tracking mounting system. The project is sited on leased land owned and located in the City of Boulder City, Nevada. This project site is located adjacent to a dry lakebed and near existing energy infrastructure. The system will consist of new high-performance HQC 72-cell Q.PEAK L-G5.2/H solar PV modules mounted on RI's DuraTrack HZ v3 single-axis trackers. The proposed design uses strings of 28 modules wired in series. These strings (up to 24) are then aggregated into combiner boxes, which are then fused at the Schneider Electric Conext SmartGen CS2200 inverters to convert the DC energy to AC energy. The AC energy will flow from the project substation through a step-up transformer approximately 7.4 miles to the Nevada Solar One (NSO) substation.

174PG estimates that the Techren Solar V will provide 90 jobs over a 2-year period during construction. After commercial operation on December 31, 2020, the Techren Solar V is expected to provide 5 permanent jobs with an average annual salary of $54,500, for a total estimated payroll of $7 million over 25 years. Overall, NV Energy estimates that the total investment in Nevada's economy directly associated with the Techren Solar V (estimated capital plus network upgrades) will be over $120 million. A work site agreement, dated April 27, 2018, was successfully executed between Techren Solar V, LLC and IBEW Local Unions 357 and 396.

The PPA is for a 25 year term with a base price of $29.89 per MWh, with no escalation. The project has an expected net capacity rating of 50 MW (AC). It is expected to generate 140,443 MWh and provide 140,443 kPCs in the first year. Annual energy production and credits are projected to degrade at approximately three-tenths percent (0.3%) per year. The PPA includes options for Nevada Power to purchase the asset at periodic intervals after commercial operation and at the end of the term. A copy of the PPA can be found in Technical Appendix REN-6-TS5 (a). Figure REN-17 shows a map of the Techren Solar V site.

FIGURE REN-17
TECHREN SOLAR V – PROJECT SITE



Technical Appendix REN-6-TS5 (b) contains detailed information about the Techren Solar V project, including the information required by NAC 704.8885 and NAC 704.8887.

6. NETWORK UPGRADES REQUIRED FOR THE NEW AGREEMENTS

The cost of new network upgrades required to connect the proposed projects was factored into the LCOE. Those network upgrades are described further in the direct testimony of Mr. Verma and below, in the Transmission Plan section of this narrative.

E. TRANSMISSION PLAN

1. INTRODUCTION

The regulations governing integrated resource planning require that the Companies include in their triennial IRPs a 20-year plan to meet the transmission needs of native load customers,[29] and service requests from third parties.[30] This transmission plan is built upon the load forecasts, system characteristics, existing and future transmission facilities and obligations as described in this section. Based in part on these key system characteristics, the transmission plan examines the capabilities of the existing transmission system in order to determine the need for and timing of any additional transmission facilities.

The Companies are requesting Action Plan approval to begin network upgrades associated with six new Generator Interconnection projects. These include network upgrades required to support the development of the following generation projects: Dodge Flat Solar, Fish Springs Ranch Solar, Eagle Shadow Mountain Solar Farm, and Copper Mountain 5. The Companies are also requesting Action Plan approval to upgrade conductor on a 1.45 mile section of the Arden to McDonald 230 kV line as a result of the previously approved McDonald 230/138 kV transformer addition. The Companies are also requesting approval to continue participation in WestConnect with funding of approximately $675,000 distributed equally over the three-year Action Plan period.

Updates regarding four previously approved projects are being presented for informational purpose only. The Companies are not making any requests for changes in authorizations related to the McDonald 230/138 kV Substation upgrade (southern Nevada), the East Tracy 345/120 kV Transformer addition (northern Nevada), the Bordertown to California 120 kV project (northern Nevada), and the Grid Resilience program (both northern and southern systems). A detailed discussion regarding the unprecedented load growth in the Tracy Area (located outside Reno) is provided, which describes existing system limitations and the timing requirements for investment to facilitate and sustain that growth. An updated discussion regarding timing and requirements for retirement of North Valmy Unit 1 is also included in this narrative.

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[29] The term "Native Load Customer" comes from regulations established by the Federal Energy Regulatory Commission ("FERC") creating and maintain their open access transmission policies. Nevada Power and Sierra operate a single Balancing Area Authority or ("BAA"), which is responsible for serving both native load and transmission-only customers. Native load customers are the bundled retail customers of both Nevada Power and Sierra. Native load customers do not plan for and purchase transmission access directly from the BAA. Instead, Nevada Power and Sierra plan for and reserve transmission access on their behalf, consistent with the FERC's open access transmission policies, and pursuant to the Companies' Open Access Transmission Tariff or "OATT".

[30] *See*, NAC § 704.9385(3).

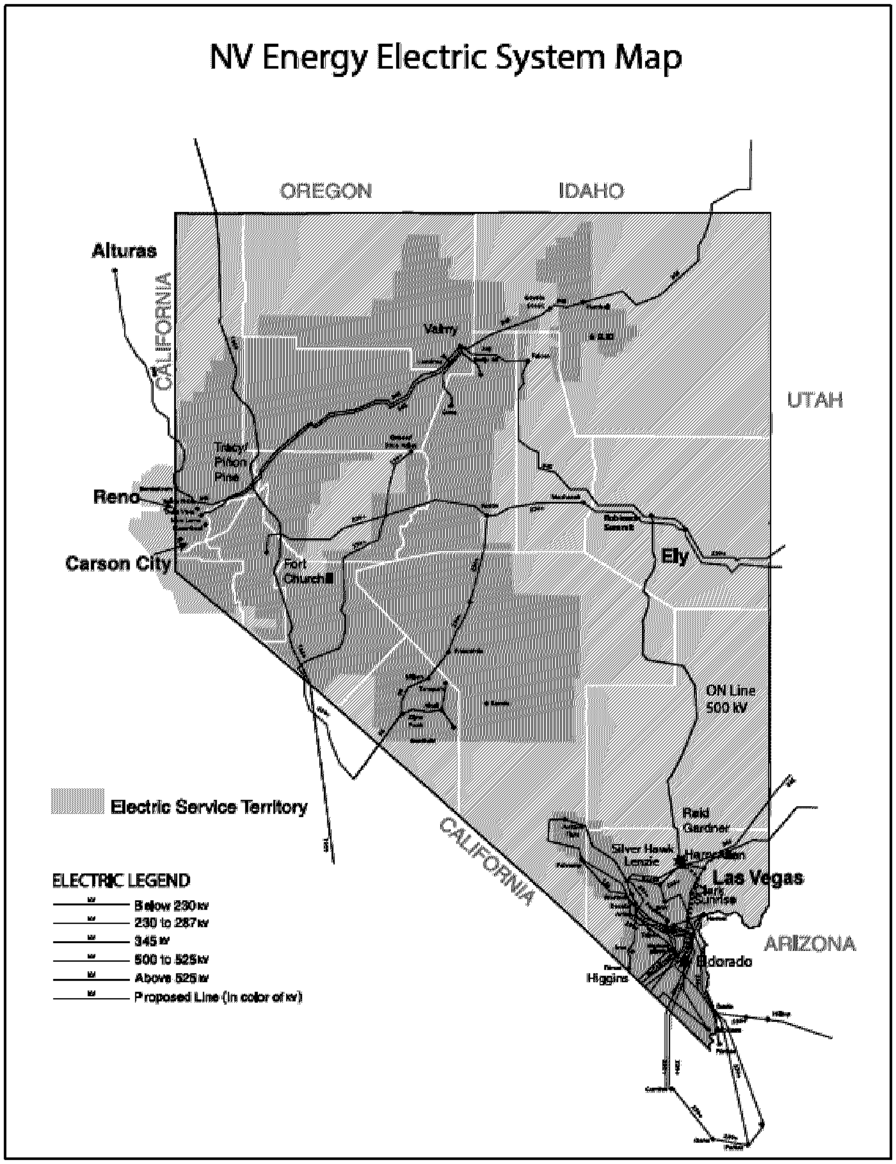
2. OVERVIEW OF THE COMPANIES' TRANSMISSION SYSTEM

Section 704.9321(3)(e) of the NAC requires the Companies to provide maps depicting facilities required for the transmission of electric energy. This information is set forth in the map marked as Figure TP-1 below. This map shows the transmission system in both the northern and southern parts of Nevada, at each voltage.

The consolidated Nevada Power and Sierra transmission BAA encompasses approximately 50,000 square miles. Nevada Power owns 1,665 miles of FERC-jurisdictional transmission lines with voltages ranging from 69 kV to 500 kV. The Sierra transmission service area encompasses more than 40,000 square miles, with approximately 330,000 electric customers and 2,151 miles of FERC-jurisdictional transmission lines ranging from 55 kV to 345 kV.[31]

[31] Total Sierra transmission line mileage for both FERC-jurisdictional and Nevada jurisdictional facilities is 4,157 miles with voltages ranging from 55 kV – 345 kV. This excludes the 235 mile 500 kV One Nevada Transmission Line ("ON Line"). ON Line is included as part of Nevada Power's overall transmission system.

FIGURE TP-1
NV ENERGY TRANSMISSION SYSTEM DIAGRAM



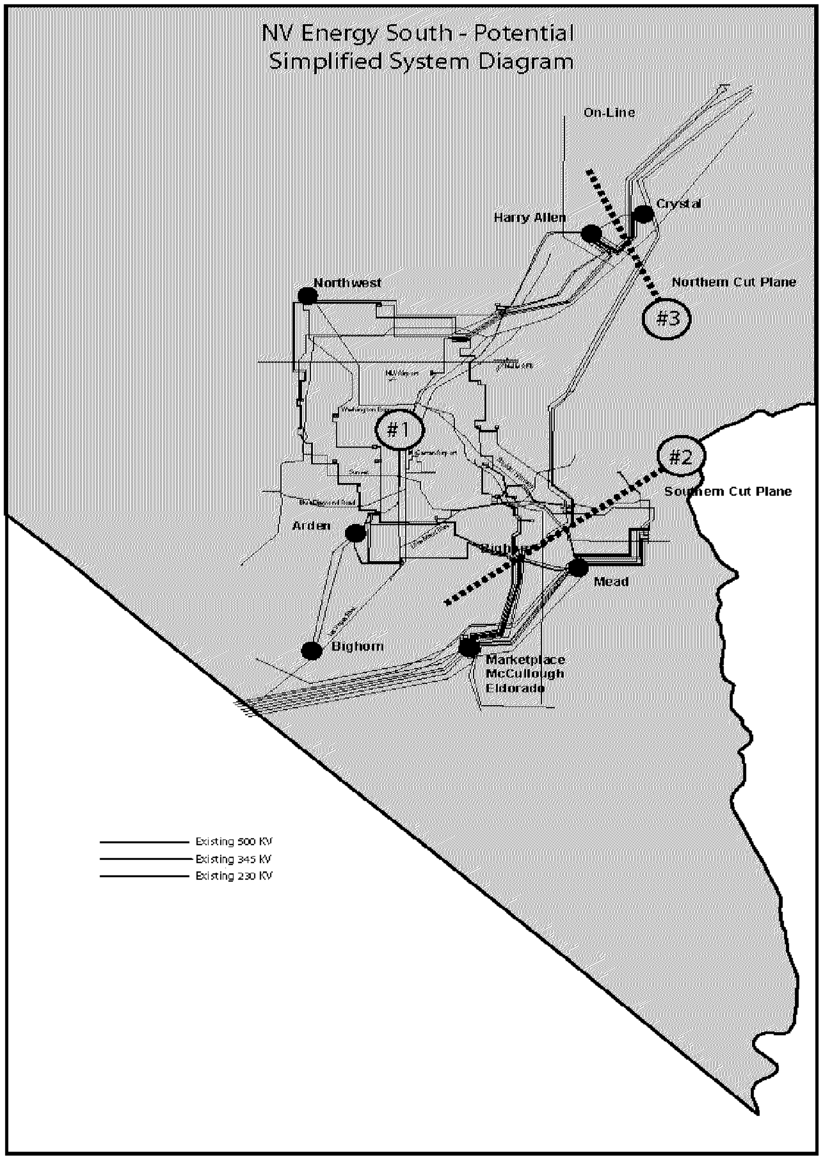
a. NEVADA POWER TRANSMISSION SYSTEM

The existing Nevada Power transmission system can be described in three sections, each of which is depicted in Figure TP-2. The first section, generally referred to as the Nevada Power internal system, is designated by the "#1", and is shown as the area between the cut plane lines (the heavy dashed lines). A cut plane is a reference to a combination of lines, either internal or external to a transmission system, which due to loading capabilities are collectively monitored or examined for limitations. The Nevada Power internal system is located within the Las Vegas Valley where the vast majority of Nevada Power's customers reside.

Two import/export paths are also depicted. The second section, designated with a "#2", is identified by the dashed line on the bottom-right of Figure TP-2. This transmission path is known as the Southern Cut Plane ("SCP"), and shows the transmission lines Nevada Power uses to transfer power through major substations on the southern interface of its transmission system – namely Mead, McCullough, and Eldorado – located south of Las Vegas in the Eldorado Valley. As detailed later under the Transmission Path Ratings portion of this plan, the SCP has been replaced by the formally accepted Western Electricity Coordinating Council ("WECC") path known as the Southern Nevada Transmission Interface ("SNTI"). The SNTI is composed of numerous transmission lines electrically situated in parallel with each other. These lines are connected to the Mead, McCullough, and Eldorado substations, which are prominent trading hubs south of Nevada Power's transmission system and are used to import and export energy that is scheduled across this newly rated path.

The third section is represented by the dashed line on the top-right of Figure TP-2, designated with a "#3", is referred to as the Northern Cut Plane ("NCP"), and comprises the Red Butte-Harry Allen 345 kV interconnection with PacifiCorp, and the Crystal interconnection with the Navajo-Crystal-McCullough 500 kV line. Annual studies are conducted in coordination with PacifiCorp to verify the capability of this cut plane.

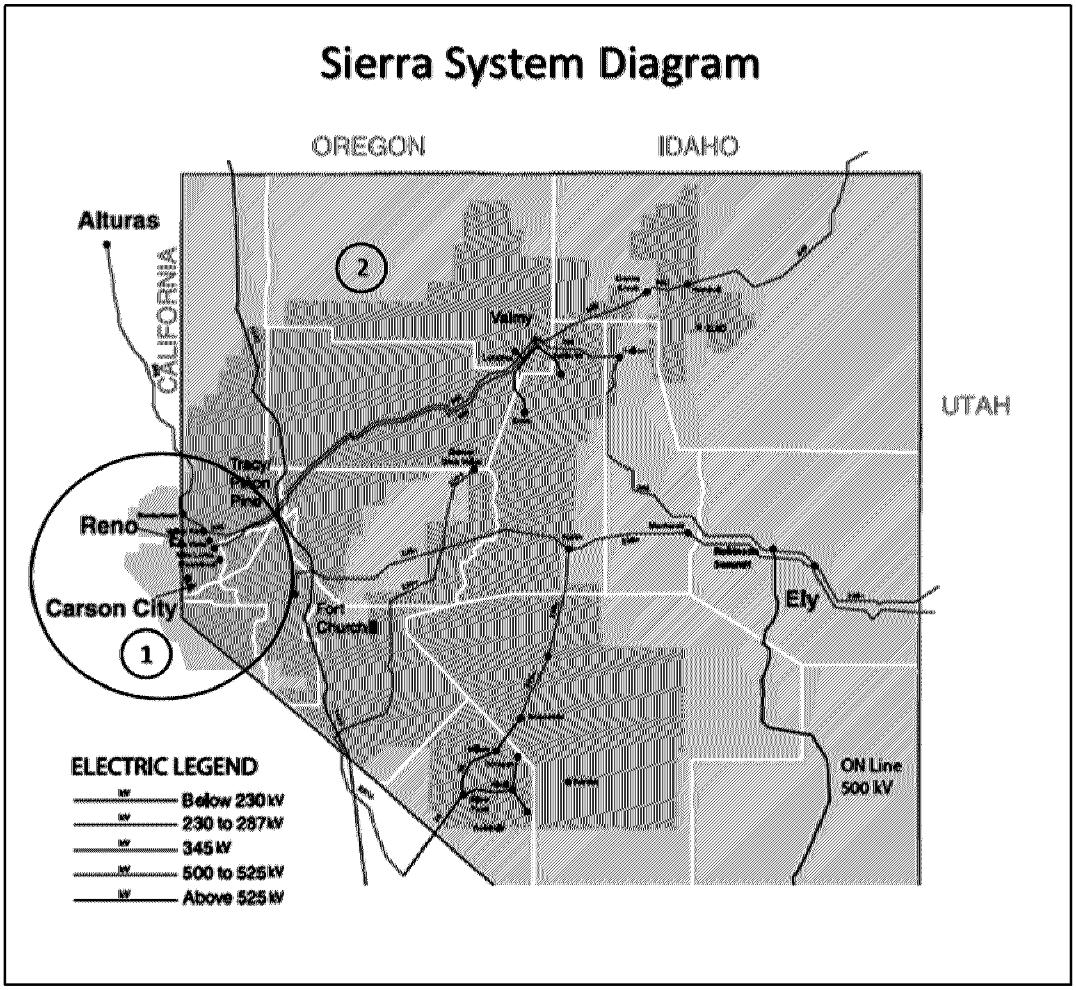
FIGURE TP-2
NEVADA POWER TRANSMISSION SYSTEM DIAGRAM



b. SIERRA TRANSMISSION SYSTEM

The Sierra system is best described as two sections as shown in the map in Figure TP-3 below. The first section, depicted as the area within the circle, encompasses the Reno, Tracy and Carson City areas. Designated with a "1", this section represents the majority of the Sierra system load, and is where the majority of Sierra's customers reside. The second section of the Sierra service area is the area outside the inner circle, designated with the "2", in the northern portion of the state. This section is characterized by long transmission lines serving heavy industrial (i.e., mining) and rural load widely dispersed throughout the northern portion of the state.

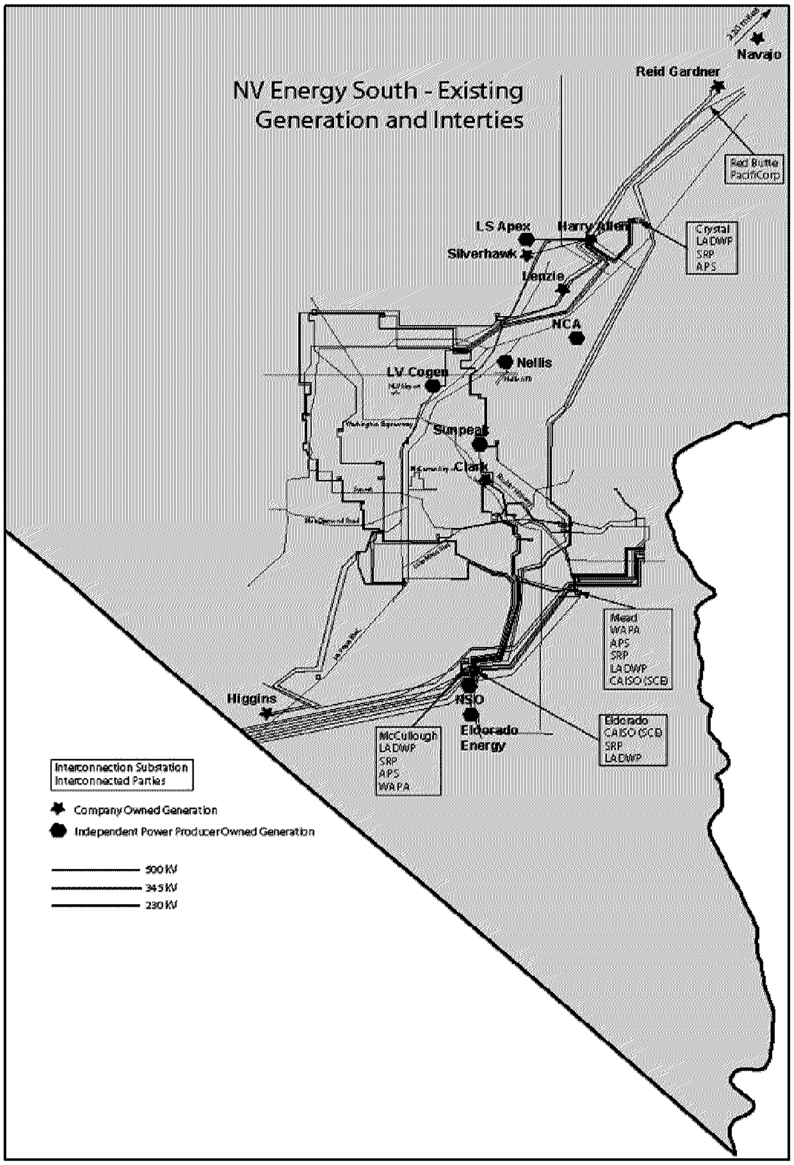
FIGURE TP-3
SIERRA TRANSMISSION SYSTEM DIAGRAM



3. TRANSMISSION PATH RATINGS

Per NAC §704.9385(3)(a), the Transmission Plan must provide a summary of the capabilities of the transmission system, including import and export capabilities and the rating of significant transmission paths. NAC §704.9321(3)(d) requires the Companies to provide information regarding interconnections with other utilities and independent power producers. Nevada Power owns three significant rated transmission paths, as shown below in Figure TP-4, each consisting of one or more transmission lines that are granted a rating by the WECC. Nevada Power is a partial owner of one additional WECC-rated transmission path, that being the WECC East of River ("EOR") Path 49.

FIGURE TP-4
DIAGRAM OF NEVADA POWER TIE LINES, EXISTING COMPANY-OWNED GENERATION, AND EXISTING INDEPENDENT GENERATION



<u>Crystal 500 / 230 kV Path (WECC Path # 77)</u>. The Crystal 500/230 kV path allows energy to be moved from the Navajo-Crystal-McCullough 500 kV transmission line into the northeast boundary of the Nevada Power system via its Crystal Substation. This path is rated for 950 MW of inbound flow measured at the Crystal Substation. This is a 230 kV phase shifter-controlled path.

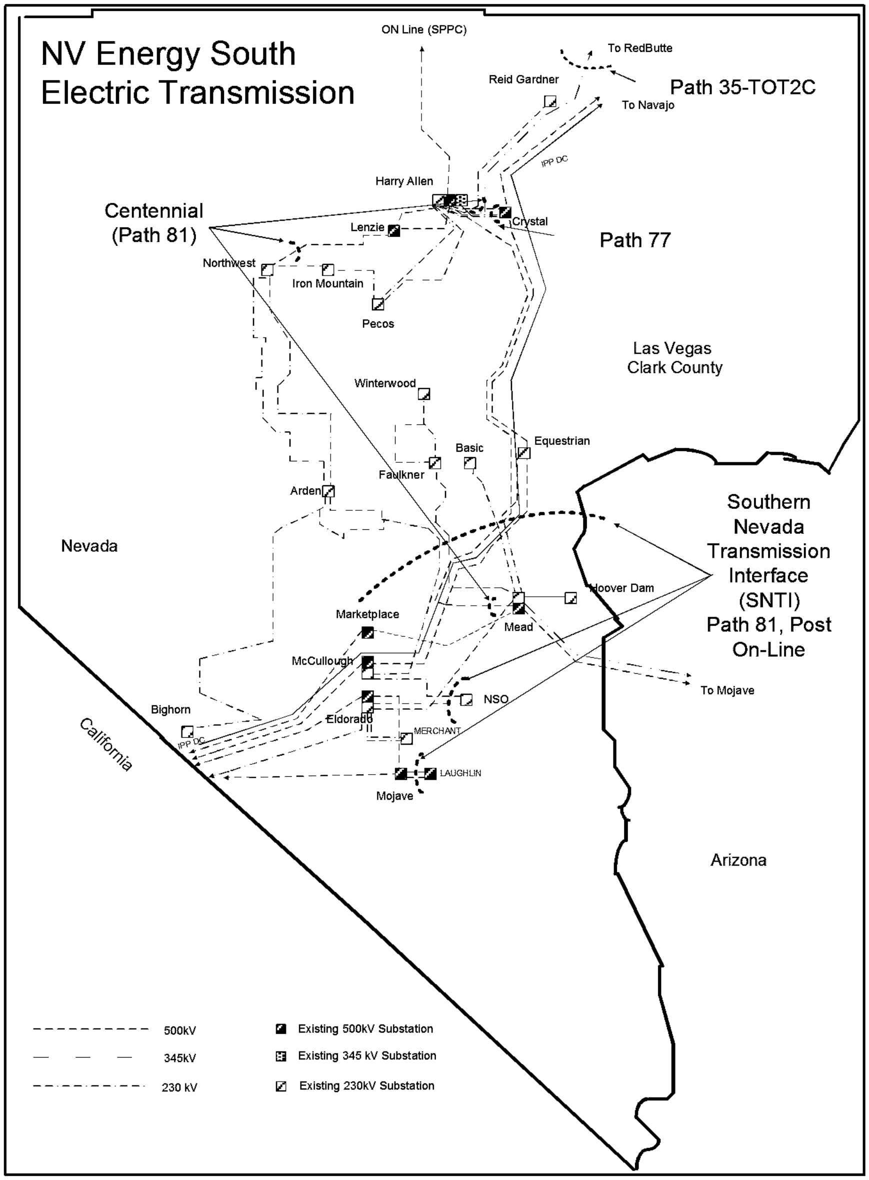
<u>Harry Allen – Red Butte 345 kV Path (WECC Path # 35 – TOT2C)</u>. The Harry Allen to Red Butte 345 kV path allows energy to be moved to and from Utah (PacifiCorp – East) and the northeast corner of the Nevada Power system at the Harry Allen switching station. The two phase shifters at Harry Allen control the flow on this path and they are occasionally used to mitigate

unscheduled flow in the WECC interconnection. This path has a north to south rating of 600 MW and a south to north rating of 580 MW

Southern Nevada Transmission Interface (WECC Path #81). Nevada Power owns and operates the Southern Nevada Transmission Interface, or SNTI, shown below in Figure TP-5. SNTI is comprised of 21 transmission tie-lines between the Nevada Power/Sierra combined BAA and the neighboring BAAs in southern Nevada (Western Area Power Administration, Lower Colorado, Los Angeles Department of Water and Power or "LADWP", and the California Independent System Operator Corporation ("CAISO"). This can be seen in Figure TP-4. The SNTI represents existing lines, and the path is routinely evaluated and annually updated as a part of the NV Energy seasonal operating studies. The accepted SNTI rating as approved by WECC is 4,533 MW North-to-South and 3,970 MW South-to-North.

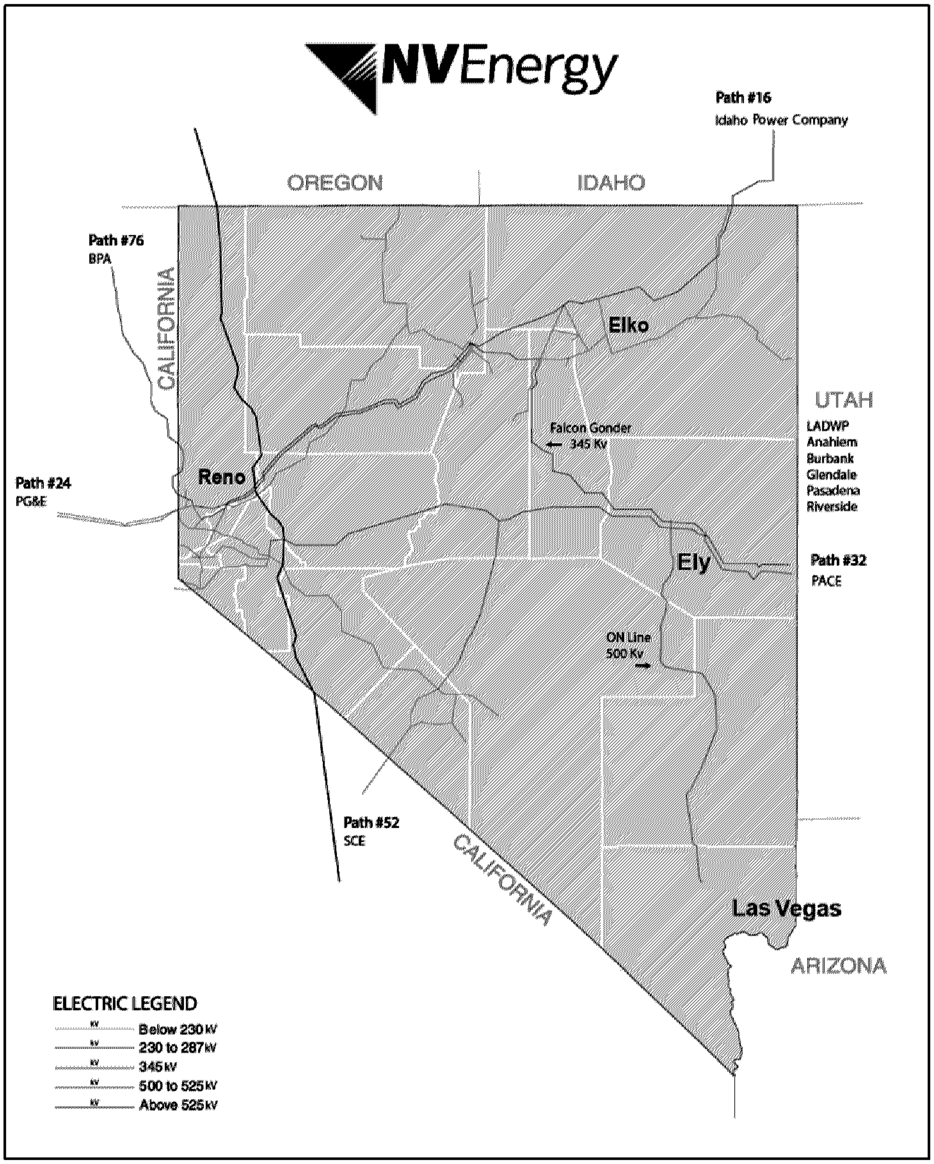
Regional Projects Affecting Nevada Power Capacity Rights. In 2014, the CAISO announced its intent to seek bids for the construction a new 500 kV transmission line between Nevada Power's Harry Allen substation and Southern California Edison's ("SCE") Eldorado substation ("HAE Project"). CAISO is sponsoring the line for the benefit of CAISO and its customers. The expected in service date of the HAE Project is May 2020. LS Power Associates, L.P. ("LS Power") has been awarded the bid. Nevada Power and Sierra have executed certain agreements with LS Power to support LS Power's bid and continue to work with LS Power, CAISO and SCE on the project. The line will improve reliability of Nevada and California systems, enhance import capabilities by approximately 100 MW and increase total Nevada Power export capability through the Southern Cut Plan by approximately 1,000 MW.

FIGURE TP-5
SOUTHERN NEVADA TRANSMISSION INTERFACES



Sierra owns five WECC rated transmission paths, each consisting of one or more transmission lines. Rated transmission paths are identified in Figure TP-6 below. Ratings are established through the WECC process on a non-simultaneous basis. These transmission path ratings may be subject to change over the twenty-year planning period, depending on changes to the system configuration. Operation of the paths are based on simultaneous limits described as Operational Transfer Capabilities and are posted on Sierra's Open Access Same-time Information System ("OASIS").

FIGURE TP-6
SIERRA RATED TRANSMISSION PATHS



Idaho – Sierra (WECC Path # 16). This path is rated for 500 MW of inbound flow and 360 MW of outbound flow. The path is a 345 kV line from Idaho Power's Midpoint Substation, near Twin Falls, Idaho that connects to Sierra's Humboldt Substation in the northeast corner of the Sierra's transmission system.

Pacific Gas and Electric – Sierra (WECC Path # 24). This path has two 120 kV lines and one 60 kV line and is rated for a total flow of 160 MW in-bound and 150 MW out-bound. The path connects Pacific Gas and Electric's 115 kV system near Donner Summit, California, to Sierra's 120 kV and 60 kV transmission near Truckee, California. This path has a 150 MVA phase shifter at California Substation near Verdi, Nevada, to control the path flow.

Pavant – Gonder 230 kV and Intermountain – Gonder 230 kV (WECC Path #32). This path has two 230 kV tie lines. Total flow is rated 440 MW in-bound and 235 MW out-bound. PacifiCorp's Pavant and Los Angeles Department of Water and Power's Intermountain substations are both in Utah and each has a 230 kV line that connects to the Gonder Substation near Ely, Nevada. A 150 MVA 120 kV phase shifter at the Ft. Churchill Substation near Yerington, Nevada, has some control of the line flows on this rated path.

Silver Peak – Control 55 kV (WECC Path #52). This path is rated 17 MW bi-directionally. The path starts at Silver Peak, Nevada and ends at SCE's Control Substation, which is located near Bishop, California. This path includes two 60 kV lines and two 17 MVA phase shifters in series to control the path flows.

Alturas Project (WECC Path # 76). This path is rated at 300 MW bi-directionally. The Alturas path is connected to Bonneville Power Authority's 230 kV transmission at Hilltop 230 kV Substation near Alturas, California. Voltage is stepped-up to 345 kV at Hilltop with a 300 MVA transformer. From Hilltop, the path continues south where it interconnects with Ft. Sage Substation. This path has a 300 MVA phase shifter at Bordertown Substation to control the path flows.

4. IMPORT CAPABILITY

Section §704.9385(3)(a) of the NAC requires that the Transmission Plan describe the import capability of the transmission system. The term "import capability" is defined as the energy that can be transferred into a BAA. Import capability is determined in accordance with WECC, and North American Electric Reliability Corporation ("NERC") reliability criteria. Accordingly, the system must be capable of meeting all performance criteria for steady state and single contingency outage conditions at the stated import level. The Companies' system import capability is dependent on transmission line flows, generation dispatch patterns, and system loads.

Figure TP-7 below shows the individual system import capabilities using the FERC's prescribed methods. These values reflect the system import limit using balanced line flows with internal generation adjusted to allow maximum system import capability. This figure does not provide a complete representation of each system's real-time import capabilities, as imports are dependent on load and the generation used to meet such load. Imports equal load plus losses minus internal generation, or:

Imports = load + losses – internal generation

In real time, when all available generating units are being used to serve system load, imports will be equal to the difference between load, losses and generation. Whether the system has the capacity to perform a system wheel (*i.e.*, an import at one location in the system with a corresponding export

at a different location in the system) under these circumstances is determined through studies, which the Companies routinely complete in response to transmission service requests.

FIGURE TP-7
SUMMARY OF SYSTEM IMPORT CAPABILITY

Summary of Import Capability (MW)					
	2017	**2018**	**2019**	**2020**	**2021+**
Nevada Power	5100	5100	5100	5200	5200
Sierra	1275	1275	1275	1275	1275

Maximum import capability should not be confused with long-term, firm transmission capability under the OATT. Maximum import capability is measured using maximum load and minimum generation, where actual imports are highly dependent on load, generation and available voltage support. Long-term, firm transmission service under the OATT must be available without limits imposed by load variations or other transmission customers' actions.

5. EXPORT CAPABILITY

Section 704.9385(3)(a) of the NAC also requires that the Transmission Plan describe the export capability of the transmission system. Nevada Power's and Sierra's system export capability are set forth in Figure TP-8 below. Export capability is limited by the capability of the transmission system, including load and generation. Export capability of the system is limited by the loss of the highest rated intertie.

Maximum export capability should not be confused with the Companies' long-term, firm transmission capability under the OATT. Each system's maximum export capability is determined using minimum load and maximum generation resources within the system. Actual exports are highly dependent on load and generation. Long-term, Firm Transmission Service under the OATT must be deliverable without limits imposed by load variations or other transmission customers' actions.

FIGURE TP-8
SUMMARY OF EXPORT CAPABILITY

Summary of Export Capability (MW)					
	2017	**2018**	**2019**	**2020**	**2021+**
Nevada Power	4465	4465	4465	5465	5465
Sierra	750	750	750	750	750

6. TRANSMISSION SERVICE OBLIGATIONS

Per NAC §704.9385(3)(c) and NAC §704.9385(3)(d), the transmission plan must identify the transmission capacity required to serve bundled and unbundled retail transmission customers, and wholesale transmission customers the Companies are obligated to serve, as well as all existing and proposed transmission service agreements ("TSAs"), with transmission customers, the expiration dates of those obligations and their impacts on the transmission capacity available for use by bundled retail customers. Nevada Power and Sierra are obligated to provide transmission-only service to several transmission-only customers under TSAs. Existing Nevada Power TSAs are listed in Figures TP-9 and TP-10. Figure TP-9 lists Nevada Power's long term transmission obligations for import into the BAA. Figure TP-10 lists Nevada Power's long term transmission obligations for exports out of the BAA. Existing Sierra TSAs are listed in Figures TP-11 and TP-12. Figure TP-11 shows Sierra's long term transmission obligations for import into the BAA, and Figure TP-12 shows Sierra's long term transmission obligations for exports out of the BAA. The impact of these combined TSAs on the amount of import transmission capacity available for use by bundled retail customers is reflected in the Transmission portion of the Load & Resource tables in Figures TP-13 and TP-14.

FIGURE TP-9
NEVADA POWER'S LONG-TERM BAA TRANSMISSION IMPORT OBLIGATIONS (NETWORK CUSTOMERS)

Agreement	MW	Delivery Interface	Term
SNWA SB-211	30	Mead 230	6/1/2013 - 5/31/2023
LVVWD SB-211	60	Mead 230	6/1/2013 - 5/31/2023
City of Las Vegas SB-211	8	Mead 230	6/1/2013 - 5/31/2023
City of Henderson SB-211	10	Mead 230	6/1/2013 - 5/31/2023
City of North Las Vegas SB-211	4	Mead 230	6/1/2013 - 5/31/2023
Clark County Water Reclamation District SB-211	13	Mead 230	6/1/2013 - 5/31/2023
Wynn Las Vegas	31	Mead 230	10/1/2016 - 10/1/2021
MGM Resorts Inc.	174	Mead 230	10/1/2016 - 10/1/2021
Switch Ltd.	87	Mead 230	6/1/2017 – 6/1/2047
Caesar's Enterprises	87	Mead 230	6/1/2017 – 6/1/2022

FIGURE TP-10
NEVADA POWER POINT OF DELIVERY LONG-TERM BAA TRANSMISSION EXPORT OBLIGATIONS

Agreement	MW	POR – POD	Term
ORNI 47	24	ORNI 47 – Mead 230	1/1/2014 - 12/31/2033
Salt River Project	25	SRPM – Navajo 500	2/1/2014 - 12/01/2018
ORNI 37	3	ORNI 37 – Mead 230	9/22/2015 - 12/31/2033
SCPPA	500	Harry Allen 500 – McCullough 500	12/1/2015 - 7/30/2023
ORNI 37	21	ORNI 37 – Mead 230	1/1/2016 - 1/1/2021
MSCG	50	Midpoint 345 – EDE 230	3/1/2016 - 3/1/2021
ONGP	30	ORNI 32 – Mead 230	1/1/2018 - 1/1/2023
ONGP	24	ORNI 43 – Mead 230	9/1/2017 - 9/1/2022
Patua Project	6	Ragtown 63 – Mead 230	4/1/2019- 10/1/2021
ONGP	14	Steamboat – Mead 230	2/1/2018- 2/1/2023
ORNI 43	24	ORNI 43 – Mead 230	1/1/2019- 1/1/2024
ORNI 32	30	ORNI 32 – Mead 230	1/1/2020- 1/1/2025
ORNI 52	24	ORNI 52 – Mead 230	1/1/2020- 1/1/2025
Ormat	24	Brady – Mead 230	1/1/2020- 1/1/2025
Ormat	16	Brady – Mead 230	8/1/2022- 8/1/2027
Ormat	24	Steamboat – Mead 230	12/1/2022- 12/1/2027
ORNI 43	8	ORNI 43 – Crystal 500	1/1/2018- 1/1/2019
Ormat	25	Bannock 120 – Crystal 500	1/1/2022- 1/1/2027
Ormat	25	Millers 120 – Crystal 500	1/1/2025- 1/1/2030

FIGURE TP-11
SIERRA LONG TERM BAA TRANSMISSION IMPORT OBLIGATIONS

Agreement	Delivery Interface	MW	Termination
Truckee Donner PUD	Gonder Pavant	45	11/1/2016 1/1/2025
City of Fallon	Gonder IPP	15	4/1/2017 4/1/2022
City of Fallon	Midpoint 345	10	4/1/2017 4/1/2022
Barrick	Midpoint 345	18	1/1/2016 1/1/2020
Barrick	Midpoint 345	82	1/1/2016 1/1/2029
Barrick	Midpoint 345	25	1/1/2014 1/1/2023
Barrick	Gonder Pavant	75	1/1/2014 1/1/2024
Barrick	Midpoint 345	6	1/1/2016 1/1/2028
Mt Wheeler	Gonder IPP	25	1/26/2017 6/1/2021
Mt Wheeler	Gonder Pavant	80	6/1/2016 6/1/2021
BPA – Wells	Hilltop	92	10/1/2016 10/1/2028
BPA – Harney	Hilltop	35	10/1/2016 10/1/2028
Switch Ltd.	Midpoint 345	14	6/1/2017 6/1/2047
Caesar's Enterprises	Midpoint 345	10	9/1/2017 9/1/2022
Peppermill Resorts	Midpoint 345	9	1/1/2018 1/1/2048
NV Energy	Gonder Pavant	149	1/1/2032[2]

[1] Network Customers' import rights are equal to Designated Network Resources ("DNRs") and may not have a termination date based on contract and roll-over rights.
[2] DNRs that impact transmission capacity on Path 32.

FIGURE TP-12
SIERRA POINT OF DELIVERY LONG TERM BAA TRANSMISSION EXPORT OBLIGATIONS

Agreement	POR - POD	MW	Term
Patua Project LLC	EAGLE 120 – HILLTOP 345	30	10/1/2013 10/1/2018
Patua Project LLC	EAGLE 120 – HILLTOP 345	18	10/1/2018 10/1/2023[1]
Patua Project LLC	EAGLE 120 – HILLTOP 345	24	10/1/2016 1/1/2019
Patua Project LLC	EAGLE 120 – HILLTOP 345	4	1/1/2019 10/01/2021[1]
Patua Project LLC	RAGTOWN 63 – GON.PAV	7	1/1/2019 10/1/2021[1]
Patua Project LLC	RAGTOWN 63 – GON.PAV	13	1/1/2019 10/1/2021[1]
ARP—Loyalton	LOYALTON 63 – SUMMIT 120	18	4/1/2018 4/1/2023[1]
Idaho Valmy	M345 – VALMY	262	N/A

1. Subject to roll over rights.

NAC 704.9385(3)(e) requires the Companies provide “a table identifying all the transmission capacity that the utility has secured for its bundled retail transmission customers on both its transmission system and the transmission systems of other utilities.” Figure TP-13, below lists the Companies’ long term secured transmission capacity for bundled retail customers.

FIGURE TP-13
TRANSMISSION CAPACITY SECURED FOR BUNDLED RETAIL TRANSMISSION CUSTOMERS

	Firm Capacity Reserved by NVE South Native Load Provider (NEVP)									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Mead	355	355	355	355	355	355	355	355	355	355
Red Butte	0	0	0	0	0	0	0	0	0	0
McCullough	0	0	0	0	0	0	0	0	0	0
Crystal	255	255	255	255	255	255	255	255	255	255
Eldorado	0	0	0	0	0	0	0	0	0	0
Mohave (Laughlin)	54	54	54	54	54	54	54	54	54	54
	665	665	665	665	665	665	665	665	665	665
	Firm Capacity Reserved by NVE South on Other Systems									
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
	0	0	0	0	0	0	0	0	0	0

NAC § 704.945(4) requires "a graph or table" that depicts "the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers." This information is provided for the combined companies in TP-14, below.

FIGURE TP-14
ALLOCATION OF CAPACITY OF THE COMPANIES' TRANSMISSION SYSTEM

Balancing Authority Customer Import Capacity									
2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
285	285	285	285	285	285	285	285	285	285

7. UPDATES: PREVIOUSLY APPROVED TRANSMISSION PROJECTS

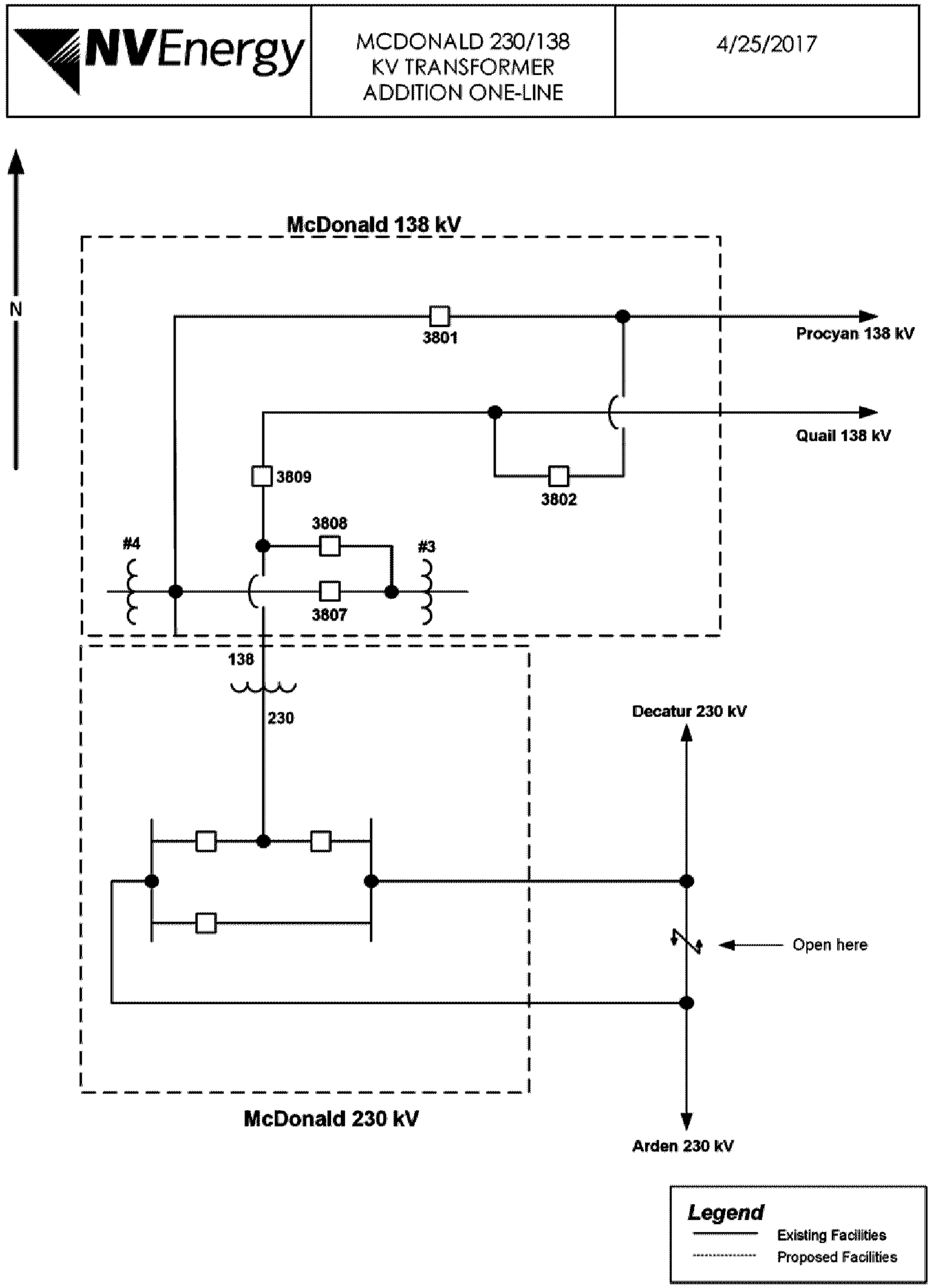
The following updates regarding four previously approved transmission projects are provided as information only. These projects include the McDonald 230/138 kV Substation upgrade, the East Tracy 345/120 kV Transformer addition, the Bordertown to California 120 kV Project and the proposal to fund the Grid Resilience program.

a. MCDONALD 230/138 KV SUBSTATION UPGRADE

Commission approval to begin work on the McDonald 230/138 kV Substation upgrade was granted following a request in the 2017 Nevada Power Third Amendment to its 2015 IRP (Docket No. 17-11004). In that docket, the Commission approved the installation of an additional 230/138

kV transformer at McDonald 230 kV Substation, with a three breaker ring substation configuration, and associated substation upgrades. See the one-line diagram of the project in Figure TP-15 below.

FIGURE TP-15
MCDONALD 230/138 KV SUBSTATION UPGRADE



In order to meet the required timeline for service, the Companies are able to use an existing spare 230/138 kV transformer to eliminate the long transformer lead time, and will order a replacement 230/138 kV transformer (which will be charged to this project) to serve the intended function of

the original transformer. Because the Companies were able to utilize an existing spare transformer, the project remains on target to meet the in service date of May 31, 2019. The original approved project budget was approximately $12.8 million. The project remains within one percent of this target, with an updated three year cash flow of $12.9 million. See Figure TP-16 below.

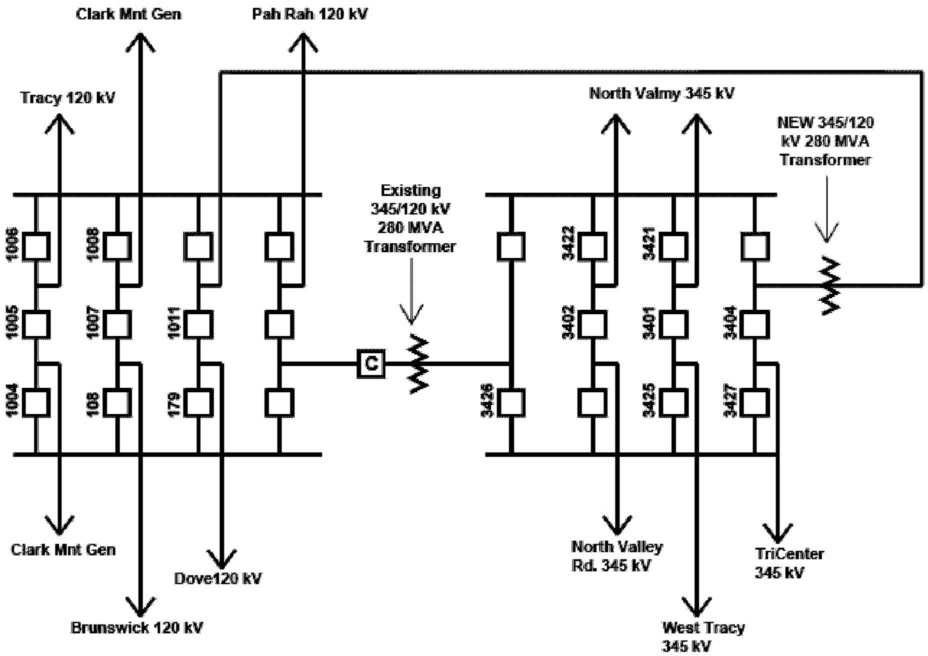
FIGURE TP-16
MCDONALD 230/138 KV SUBSTATION UPGRADE CASH FLOW

McDonald 230/138 kV Substation Upgrade						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total (2018-2020)**	**Post 2020**
$ 12,900,000	$ -	$ 1,500,000	$ 11,400,000	$ -	$ 12,900,000	$ -

b. EAST TRACY 345/120 KV TRANSFORMER ADDITION

Commission approval to begin work on the East Tracy 345/120 kV Transformer addition was granted following a request in the Second Amendment to Sierra's 2016 IRP (Docket No. 17-11003). The request included a new 345/120 kV 280 MVA transformer at the existing East Tracy 345/120 kV substation, along with necessary communication and protection upgrades. The one-line diagram of the project is shown in Figure TP-17 below. The project scope also included replacing underrated breakers at the East Tracy, Tracy, Pah Rah and Dove substations to mitigate an increase in fault duty.

FIGURE TP-17
EAST TRACY 345/120 KV TRANSFORMER ADDITION SINGLE LINE DIAGRAM



N

East Tracy
Transformer Addition

NVEnergy

EXISTING FACILITIES
PROPOSED NEW FACILITIES

The transformer has been relocated to the east side of the substation due to space constraints. The project remains on target to meet the requested in service date of June 30, 2020. The original approved project budget was approximately $10 million, and is now projected to be within one percent of the original estimate - approximately $10.1 million. The Figure TP-18 below shows the estimated cost and cash flow for the project:

FIGURE TP-18
EAST TRACY 345/120 KV TRANSFORMER ADDITION CASH FLOW

East Tracy 345/120 kV Transformer Addition						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total (2018-2020)**	**Post 2020**
$ 10,100,000	$ -	$ 2,800,000	$ 3,900,000	$ 3,400,000	$ 10,100,000	$ -

c. BORDERTOWN TO CALIFORNIA 120 kV PROJECT

This project was originally approved by the Commission in 2007 in Docket No. 07-06049. As approved, the project contemplated a 345/120 kV transformer at Bordertown Substation and 120 kV line from Bordertown to California Substation. The original approved project budget was $27 million ($22 million for the line between Bordertown and California substations, and $5 million for relocating the phase shifter from Bordertown to Hilltop Substation).

In Sierra's 2010 IRP, Docket No. 10-07003, the project scope was reduced to eliminate the relocation of the phase shifter, and the scheduled in-service date was extended from 2012 to 2014. The budget for the project was revised downward to $20.24 million. The parties to the proceeding executed a stipulation, which was approved by the Commission, which revised the project schedule.

In Sierra's 2013 IRP, Docket No. 13-07005, the project scope, schedule and budget were again revised. The budget estimate was increased to $30.4 million and the in-service date was updated from 2014 to 2016. The parties to the proceeding executed a stipulation, which was approved by the Commission, which revised the project schedule.

In Sierra's 2015 IRP amendment, Docket No. 15-08011, the Commission was informed that the Bordertown to California Substation project would be completed and placed in service in December 2016. In that filing Sierra indicated that it anticipated receiving permitting approvals in the fall of 2015.

In the fall of 2015 the U.S. Forest Service ("Forest Service") completed a Draft Environmental Impact Statement ("EIS") for the project. On March 9, 2018, the Forest Service released a draft Record of Decision and Final EIS for a 45-day formal objection period. The Forest Service accepted objections through April 23, 2018 from people who have previously submitted specific written comments regarding the proposed project during scoping or other designated comment periods. The Forest Service selected the Peavine/Poeville route alternative based upon review of analysis disclosed in the Final EIS, project record, and evaluation of the information provided by the applicant.

The Forest Service's decision is conditioned on the terms of a special use permit, implementation of project design features, and mitigation and monitoring as identified in the Final EIS and attached to the draft Record of Decision. To implement and comply with the conditions in the decision, Sierra will complete and the Forest Service must approve a Construction, Operation, and Maintenance Plan for the selected route alternative. In addition, the Forest Service continues work on a Historic Properties Treatment Plan and Memorandum of Agreement for cultural resource

mitigation. The agreement must be signed by the Forest Service, State Historic Preservation Offices and tribes.

In parallel with these activities, Sierra will work to complete design activities, acquire easements on private lands, and obtain local jurisdictional use permits. A Notice to Proceed is currently anticipated in early 2019 and the in-service date is currently estimated for early 2020. The in-service date may be extended beyond that date if the Forest Service requires additional time to address objections, complete and sign a Memorandum of Agreement, and release a Final Record of Decision. These steps are required for the Forest Service to issue a Notice to Proceed. One-line diagrams depicting the Bordertown and California substation configuration are shown in Figure TP-19 and TP-20 below.

FIGURE TP-19
BORDERTOWN SUBSTATION ONE-LINE DIAGRAM

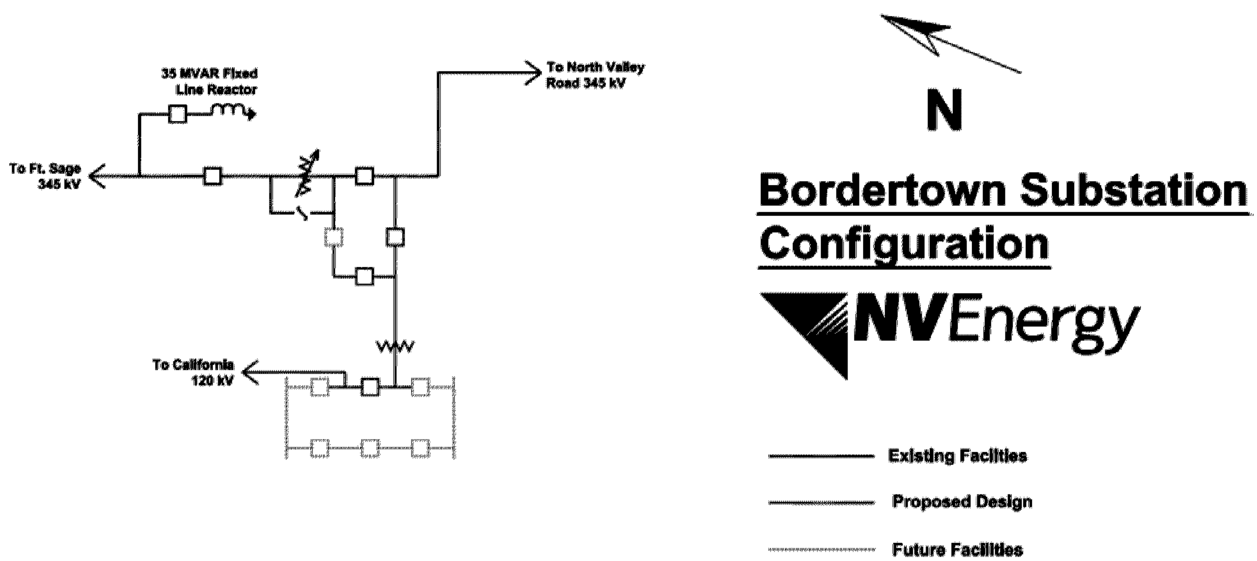
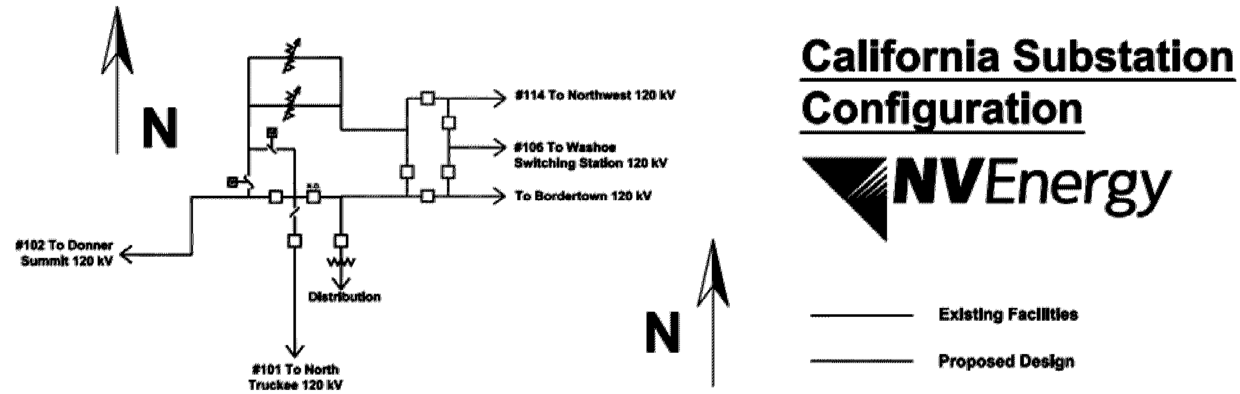


FIGURE TP-20
CALIFORNIA SUBSTATION ONE-LINE DIAGRAM



Operational limitations continue to be utilized to ensure system reliability and the project is still needed under the current system configuration.

Expenditures through 2017 total $3.809 million and current projected expenditures through the 2018-2020 Action Plan period are anticipated to be $27.562 million. The current cost at completion is approximately $1.0 million higher than the 2013 budget due to estimated increased costs for the extended permitting duration, consulting services for additional environmental permitting requirements, land survey and private easements, and a higher construction estimate for the improvements at California Substation. The Figure TP- 21 below shows the estimated cost and cash flow for the project:

FIGURE TP-21
BORDERTOWN TO CALIFORNIA SUBSTATION BUDGET

Bordertown to California Substation Project Cash Flow							
	Prior	2018	2019	2020	2021	Post	Total Cost
Bordertown to Cal Sub - Lands	$ 1,275,416.78	$ 1,975,429.78	$ 91,382.05		$ -	$ -	$ 3,342,235.55
Bordertown to Cal Sub 120kV line Environmental	$ 2,403,682.39	$ 109,361.84	$ 628,498.21	$ 93,746.49	$ -	$ -	$ 3,235,289.50
Bordertown 345/120 Transformer	$ 38,058.83	$ 210,892.90	$ 7,384,593.96	$ 994,409.18	$ -	$ -	$ 8,627,954.89
California Sub Rebuild	$ 8,732.53	$ 279,403.38	$ 3,804,204.76	$ 710,048.97	$ -	$ -	$ 4,802,389.70
Bordertown to Cal Sub - 120 kV line	$ 83,115.83	$ 402,188.76	$ 9,100,878.34		$ -	$ -	$ 9,586,182.94
120 kV Line Communications	$ -	$ 23,504.85	$ 1,350,990.17	$ 33,835.58	$ -	$ -	$ 1,408,330.60
Bordertown to Cal Sub Rebuild Communications	$ -	$ 15,877.74	$ 238,834.74	$ 113,643.65	$ -	$ -	$ 368,356.14
Bordertown to Cal Sub - Total	$ 3,809,006.36	$ 3,016,659.25	$ 22,599,382.24	$ 1,945,683.87	$ -	$ -	$ 31,370,739.31

d. GRID RESILIENCE PROGRAM

The Grid Resilience program was approved by the Commission in Nevada Power's IRP amendment Docket No. 17-11004. The program addresses the increasing risk to utilities of catastrophic damage to critical substations as a result of physical attack, natural disaster, or extreme weather conditions.

As approved, five transformers were identified for procurement: one 230/138 kV 336 MVA transformer, one 525/230 kV 600 MVA transformer, and three single phase 525/230 kV 500 MVA transformers. The Companies are in the process of procuring all five transformers, which will be designated as available to mitigate extreme events. The original approved project budget was approximately $17 million. Due to decreased transformer costs, the project budget is now projected to be approximately $15 million. Figure TP-22 below shows the estimated cost and cash flow for the project:

FIGURE TP-22
GRID RESILIENCE TRANSFORMER ACQUISITION BUDGET

Grid Resilience Transformer Acquisition						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total (2018-2020)**	**Post 2020**
$ 15,000,000	$ -	$ 6,850,000	$ 8,150,000	$ -	$ 15,000,000	$ -

8. SIERRA LOAD GROWTH, TIMING AND SYSTEM LIMITATIONS

As has been described in previous IRP filings, there is a high level of uncertainty associated with the accelerating load growth in the Tracy Area of the northern system. An unprecedented number of customer load requests have been received, with loads in excess of 1,449 MW being proposed by potential customers and studied by Sierra. A number of these customers, representing loads of approximately 913 MW, have already entered into High Voltage Distribution Agreements ("HVDAs") with Sierra to secure the construction of local area distribution and transmission facilities. A subset of these customers, representing [redacted] of new load, have indicated in writing that they are considering options for procuring their own generation capacity under NRS Chapter 704B. While this load is being planned for by the local area distribution system (through Sierra's Rule 9 and the HVD tariffs), these customers have yet to submit the required application for transmission service through the OATT process, or to file a Chapter 704B application with the Commission. The inconsistencies between the three service processes (local area distribution and transmission service subject to state regulation and control, bulk transmission service subject to FERC regulation and control, and retail open access options subject to state regulation and control) are adding complexity to the already challenging task of planning for unprecedented local area growth. If, as expected, customers representing a significant amount of this load opt to procure their own energy supply (becoming distribution and transmission-only customers), and if, as

expected, these customers choose to rely to one extent or another on the regional wholesale market to serve their load, additional import capacity will likely be needed to fulfill their OATT requests. In this event, once transmission service requests are made pursuant to the OATT, the Companies will face substantial timing challenges to permit and construct the new transmission facilities needed to satisfy service requests. The confidential table in Figure TP-23 summarizes the load addition proposals.

Figure TP-23
PROPOSED LOAD ADDITIONS IN THE TRACY AREA

Customer	Proposed Loads (MW)	Executed HVD	Expected Retail	Indicated 704B
[redacted]				
Total (MW)	**1449**	**913**	[redacted]	

a. **THE TRACY AREA**

The Tracy Area Master Plan was originally introduced and discussed in Sierra's Second Amendment to its 2016 IRP, Docket No. 17-11003. There Sierra described the limitations on the load serving capability of this area of the system – approximately 350 MW due to available 120 kV generation and the energy transfer capability from the 345 kV system onto the 120 kV system. The 345/120 kV East Tracy Transformer addition, also described in Docket No. 17-11003, helps to increase this transfer capability, but if the aggressive load growth on the 120 kV system is realized, additional transfer capacity will be required to move generation from the 345 kV system to the 120 kV system. Importantly, Sierra's existing substations in the area do not have the additional expansion capability needed to accommodate additional 345/120 kV transformers to help alleviate this constraint. The most likely solution will require the addition of one or two new 345 kV sources from East Tracy and/or West Tracy to the proposed Comstock Meadows Substation, as well as the installation of up to five 345/120 kV transformers at this location. The quantity and timing of 345 kV sources and transformers depends on how the proposed load materializes on the system.

Due to existing capacity and timing of customer load ramping requests, it is expected that the need for initial additional 345 kV upgrades will be triggered when load a [redacted] causes loads on the 120 kV loop to reach approximately 350 MW. Based on the HVDA in place with [redacted]

[redacted], Sierra is required to design, build and construct the required 345 kV facilities within 24 months of notification. This timeline is based on when the total load in the 120 kV loop exceeds 350 MW with inclusion of the [redacted] load. It is also possible that other loads on the 120 kV system could trigger these upgrades, under these circumstances Sierra will need to act quickly to obtain Commission approval for the 345 kV facilities through an IRP amendment. The initial 345 kV facilities are summarized in Figure TP-24 below.

FIGURE TP-24
PRELIMINARY 345 KV UPGRADES TO TRACY AREA

COMSTOCK MEADOWS - 345KV SERVICE PLAN

		UPGRADE	CLASSIFICATION	ESTIMATED COST
Assumes two 345kV lines and two transfomers	Communications	Fiber on 345kV Line, W. Tracy		745,000
		Fiber on 345kV Line, E. Tracy		819,500
		W. Tracy Sub		130,000
		E. Tracy Sub		100,000
		Comstock Meadows		200,000
	Lands	345kV Line, W. Tracy		160,000
		345kV Line, E. Tracy		176,000
		Environmental		186,500
	Trans. Line	345kV Line from W. Tracy to Comstock Meadows		11,000,000
		345kV Line from E. Tracy to Comstock Meadows		12,100,000
	Substation	345kV Terminal at W. Tracy Sub		990,000
		345kV Terminal at E. Tracy Sub		2,700,000
		Comstock Meadows 345/120kV Sub, Initial Transformer & 345kV Yard		8,344,000
		Comstock Meadows 345/120kV Sub, 2nd Transformer		10,900,000
	[redacted]			
			UTILITY COST RESPONSIBILITY	48,551,000

The facilities identified in TP-24 will be required regardless of whether [redacted] ultimately elects to supply its own generation resource(s) under NRS Chapter 704B or chooses to become a bundled customer of Sierra, unless it locates its designated resource at or near the Tracy 120 kV system.

b. THE GREATER NORTHERN SYSTEM

In addition to the limitations of the Tracy Area 120 kV system, this unprecedented growth is creating concerns regarding resource adequacy in the greater northern system. Assuming that existing generation and full system import capability is available given that the Sierra system is import constrained, there is a specific level of load growth above which Sierra will no longer be able to meet NERC reliability requirements. In order to determine what that system breakpoint is, the Companies performed an analysis that assumed that all generation currently in the system remains available to meet load. This analysis is attached as confidential Technical Appendix TRAN-1.

For this analysis, in order to reflect actual generation capabilities at summer peak, geothermal and solar generation were reduced to reflect early evening hours. Solar generation was modeled at approximately 45 percent of nameplate capacity to reflect less direct sunlight at the time of summer peak. Geothermal generation was modelled at approximately 70 percent of nameplate capacity to reflect output at higher temperatures. Traditional gas and coal generators were modelled at 95 percent of nameplate capacity.

This analysis determined that internal resources and existing transmission import capability will be inadequate to meet system reliability needs once load reaches 2,600 MW, an additional 800 MW. At that point, additional resources, either internal generation or transmission, or both, will be required to continue to reliably operate the system. The analysis assumes that both North Valmy generation units are available. However, as discussed in the Generation portion of this Narrative, the Low Carbon Case retires North Valmy Unit 1 by December 31, 2021 and North Valmy Unit 2 is scheduled for retirement by December 31, 2025. With only one of the two North Valmy units available, the system capability is even further reduced. In this scenario, the system breakpoint is reduced to a total load of 2,600 MW or just 300 MW of load additions.

c. TRANSMISSION SOLUTIONS

The design and construction of any new major transmission resource into the system can take many years (generally, seven to ten years, assuming no interruption in critical path items). The initial step is a routing and constraint study, which typically takes approximately six months to prepare. Given the predominance of federal lands in Nevada, new transmission into and through Nevada generally requires the preparation by the Bureau of Land Management ("BLM") of either an Environmental Assessment or an Environmental Impact Statement. These analyses can take up to four years to complete. Line design and construction can take two to four years to complete.

The Companies have reviewed options for increasing import capability by adding transmission sources into the Sierra system. These include strengthening an existing intertie or adding external interconnections.

- Additional connections from Robinson into the Sierra system have the potential to strengthen the south to north capability of ON Line, and so were studied. These types of connections resulted in only a modest increase (approximately 125 MW) in import capability.
- Connections to the exterior of the system such as at the Northwest Substation (in southern Nevada), Captain Jack Substation (at the California Oregon Border), and the Eldorado Substation (also in southern Nevada) resulted in increased import capability of approximately 925 MW.

- A strong potential candidate for an external connection is a 350 mile 500 kV line from the Harry Allen substation to Northwest to Ft. Churchill, historically referred to as the Westside Tie. This project would create a second connection from the Nevada Power system to the Sierra system, as well as open up additional transfer capability from power markets connected to southern Nevada, such as Eldorado and Mead substations. Underlying 345 kV transmission would connect from Ft. Churchill to the Mira Loma Substation in Reno and the Comstock Meadows Substation at Tracy. This particular line integrates well with the Tracy area load growth by delivering import capability directly into that area. Preliminary analysis has identified an increase in import limit of approximately 925 MW. Additional analysis will continue to be performed to identify the preferred next major transmission path into the Sierra system.

The Companies play a vital role in providing the required facilities for both its bundled retail and transmission customers. Procedures, funding and cost allocations must be managed properly, in compliance with both state and federal rules requiring accurate cost and rate allocation and compliance with FERC's open access tariff requirements as well as Rule 9 regulations. At the same time, facilities must be planned in accordance with customer schedules in order to meet load growth milestones.

Under the traditional planning paradigm, the Companies hold the obligation and can deploy the tools to meet retail load growth, even unprecedented load growth, through the lowest cost combinations of demand- and supply-side options, including renewable and conventional generation, as well as transmission and high-voltage distribution infrastructure. Under their respective line extension rules, distribution infrastructure, transmission improvements and even large-scale generation additions are planned for through a process designed to allow flexibility as system loads grow. The Companies are able to plan for load growth in phases and adapt to changes in customer needs – whether timing or quantity – as they occur. The IRP and general rate case processes allow for checks and balances that ensure that investments to serve load are prudently planned for, purchased and constructed. Working hand-in-hand with customers, planning is a cooperative process aimed at promoting and facilitating economic growth. Certain areas of the system are staged for more growth than others. Master plans are developed in these areas to allow for expandability and future growth.

System planning has become more complicated as a new customers seek commitments from the Companies to add distribution and transmission facilities sufficient to accommodate large load additions, without at the same time committing to an energy and capacity solution. When a new or existing distribution-only service customer seeks to bring new load onto the system and to meet that load with generation resources that will be designated at a later date, the mechanism for approaching the utility is through under the FERC's OATT Transmission Service Request ("TSR") process. This process was introduced briefly in the discussion of Tracy Area constraints above.

The OATT identifies fixed and specific timelines and requirements that are triggered by the submittal of a TSR. Once a customer submits a TSR, the tariff leaves little room for flexibility or changes in project scope or timing. Facilities that are identified as a result of a TSR study process are to be securitized by the transmission customer before detailed planning, permitting and construction can begin. Thus customers are reluctant to enter into the TSR process until the last possible moment. Thus, while at this time Sierra has entered into HVD agreements [redacted] hat are sufficiently flexible to accommodate changing distribution facility requirements, neither customer has submitted a TSR as required by the OATT. Thus transmission system planners face a significant level of uncertainty until requirements are fully identified. In the interim, it is very difficult to make planning decisions for the overall system.

When system planning becomes divorced from the IRP process and is performed instead under the FERC OATT, synergies and efficiencies, as well as flexibility to meet changing customer requirements, are lost. Individual service solutions are isolated from one another, resulting in a potentially disjointed, duplicative and less comprehensive and efficient approach to system planning. The Companies will continue to balance customer expectations and commitments in order to ensure timely and reliable service to all types of customers. However, as planning for transmission and generation resources moves outside the IRP process, a new approach for facilitating economic development opportunities, and making investments needed to meet customers' expedited in service schedules will have to be fashioned.

9. NORTH VALMY UNIT 1 2021 RETIREMENT: TRANSMISSION SYSTEM CONDITIONS

The Generation and Economic Analysis sections of this Narrative explain that the Low Carbon Case retires North Valmy Unit 1 early, on December 31, 2021 instead of December 31, 2025. Several transmission-related issues are raised by the December 31, 2021 retirement of North Valmy Unit 1. The first issues are specific to system reliability and the Companies' ability to meet load service obligations: a local transmission constraint in northeastern Nevada and resource adequacy due to the growing loads in northern Nevada.

The local transmission constraint was described in the Transmission North Valmy LSAP, filed on February 16, 2018 in Docket No. 16-07001. As is discussed in the Transmission North Valmy LSAP, the Carlin Trend load pocket, the geographic center of Nevada's mining industry, has limited transmission connections and is highly dependent on both North Valmy generation and the output from Newmont's coal-fired generator (known as the TS Power plant). Maintenance of the 345 kV transmission line into the Carlin Trend cannot be reliably performed unless at least one of these generators is operating. Sierra's contract to purchase the output from the TS Power plant expires in 2023. Moreover, both Sierra's and Newmont's abilities to contract beyond 2023 are less than certain today. Sierra and Nevada Power may be barred from acquiring the output from the TS

Power plant beyond 2023 by Ballot Question 3, and factors outside Sierra's control may impact Newmont's plans for the TS Power plant in that time frame. Accordingly, there is significant uncertainty regarding whether Sierra will have the ability to call on the TS Power plant to provide support for the Carlin Trend once the existing contract with Newmont expires. Assuming an early retirement of North Valmy Unit 1 and the unavailability of TS Power plant beyond 2023, the system inches closer to the edge of unacceptable system reliability. Either maintenance at North Valmy Unit 2 or a forced outage leaves the system one 345 kV transmission line contingency away from having to shed system load to meet real time reliability requirements.

Rapid system load growth, especially in and around the Tracy area, also plays a factor in evaluating the early retirement of North Valmy Unit 1. With limited transmission import into northern Nevada, system load growth is heavily dependent on the availability of balancing area generation. Early retirement of North Valmy Unit 1 will drop 260 MW of generation off the system, reducing the maximum amount of load that can be served within the northern system, at least by Sierra's share of the unit. Simulations of this scenario using the Action Plan load forecast for both native and non-native load, did not identify blatant resource deficiencies over the twenty-year planning period. Note, however, that the Action Plan load forecast predicts a total system peak load of 2,605 MW in 2046. Although it attempts to, system modeling and load forecasting cannot predict every possible condition that could occur. As described in the Sierra Load Growth, Timing and Limitations section above, over 1,400 MW of load growth is currently being proposed in northern Nevada. Without the availability of North Valmy Unit 1, existing resources in the system become inadequate when the total northern system load reaches approximately 2,600 MW. At that point, the Companies will no longer meet system reliability reserve requirements and the sustained loss of any resource could result in load loss, voltage collapse or cascading outages.

If approved, the 401 MW of solar PV capacity and 100 MW of energy storage requested in this filing will help to alleviate this problem by increasing the maximum system load break point from 2600 to 2800 MW and facilitate the early retirement of North Valmy Unit 1. However, if Sierra's system load grows as proposed by customers (rather than as forecasted), resource deficiency could still occur and require action, either in the form of transmission investment or the operation of generation interconnected at Valmy.

The previously filed the Transmission North Valmy LSAP proposed solutions for both the local transmission constraint and the resource adequacy concern including some form of dynamic reactive compensation to avoid voltage collapse in the Carlin Trend area.[32] Static VAR Compensation ("SVC"), Static Synchronous Compensators, or conversion of a North Valmy generating unit into a synchronous condenser were discussed. None of the three solutions have ever been implemented at either Sierra or Nevada Power, however, and issues associated with

[32] In the event TS Power Plant is unable to operate after 2023, Sierra may need to accelerate the timing of reactive support into the Carlin Trend area even without the early retirement of North Valmy Unit 1.

reliability, maintenance and continuous operation of these types of facilities are still being evaluated. The Companies are contacting vendors for dynamic reactive compensation to discuss factors like maintenance schedules, repair turnaround time, warranty and replacement cost. Engineering estimates for packaged installation will also be acquired. To further increase the Companies' understanding of this equipment, discussions with neighboring utilities to understand their experiences will also be documented. Until these concerns are alleviated, more traditional forms of voltage management such as new generation and transmission solutions are still preferred.

Another plausible alternative to dynamic reactive compensation is the connection of solar PV either directly at North Valmy or within the Carlin Trend. Newer inverter technologies claim to be able to provide reactive compensation regardless of real energy output. This would serve the same purpose as a SVC as well as inject energy into the grid.

The Transmission North Valmy LSAP also proposed a 345 kV transmission project from Robinson Summit to Ft. Churchill to Comstock Meadows. This project was based off of 600 MW of additional system load in northern Nevada and the unavailability of North Valmy Units 1 and 2, and the TS Power Plant. The increase in import capability gained by this project is a fraction of the gains that can be achieved with the Westside Tie project, however. For the type and location of load growth that is being proposed, the Westside Tie project provides a more comprehensive and long term solution for injecting energy from both southern Nevada and other available markets electrically connected to the Las Vegas Valley into the northern system.

Another developing potential solution for increasing internal resources and relieving the transmission import constraint is the extension of the Ruby Gas Pipeline into the North Valmy Station. This option, which would facilitate the conversion of one or both units from coal to natural gas, or the construction by Sierra or third parties of new generating capacity, is being studied.

The Companies have not included in this Action Plan period budget a request for approval to begin to expend the $25 to $35 million needed to commence BLM permitting for the Westside Tie. While confident that the local area distribution and transmission system upgrades being made as a result of executed HVDAs with new customers are prudent, until the Companies can answer the Commission's questions regarding whether this customer load will be served with network resources or with customer-procured resources located either within or outside the system, a request for Action Plan approval to permit the Westside Tie seems premature. However, even without clarity regarding how new customer load will be served (whether by the Companies or by the customer), the execution of new HVDAs for significant amounts of additional new load may trigger the need to seek an amendment to the Action Plan, and the approval of permitting dollars.

Regardless of when specific customer load ultimately shows up, the system breakpoint of 2600 MW remains, assuming existing resources and the unavailability of North Valmy Unit 1. The

proposed addition of 401 MW of solar PV capacity and 100 MW of energy storage requested in this filing will increase the load breakpoint. However, customers have already proposed load requests for over 1,449 MW. All options will continue to be reviewed while the Companies prepare to take action to ensure customer reliability is maintained in response to the retirement of coal generation in Nevada.

10. SPECIFIC REQUESTS FOR COMMISSION APPROVAL

The Companies are requesting Commission approval for new transmission facilities necessary to provide reliable transmission service to existing and new transmission customers. NAC § 704.9385(3)(b) requires that the Transmission Plan include a description of transmission projects that the Company is considering to expand or upgrade transmission facilities. NAC § 704.9355(1)(b) and (1)(c) require that the utilities to develop a set of analyses of its options for supply to be considered for meeting the expected future demand on its system. These analyses must include an examination of the environmental impact of each option, taking into account the best available technologies and the environmental benefit of renewable resources, including construction of new transmission facilities or upgrades to existing transmission facilities and purchase of long-term transmission rights on third party transmission facilities.

The Companies are seeking Commission approval to construct six customer-requested renewable generation interconnections: Dodge Flat Solar, Fish Springs Ranch and Battle Mountain Solar in Sierra's service territory, and Eagle Shadow Mountain Solar Farm, Copper Mountain 5, and Techren V in Nevada Power's territory. Additionally, the Companies request approval to begin a 230 kV line upgrade on a section of the Arden to McDonald 230 kV line to mitigate a potential NERC TPL-001-4 violation identified as a result of the previously approved McDonald 230/138 kV Substation Upgrade project.

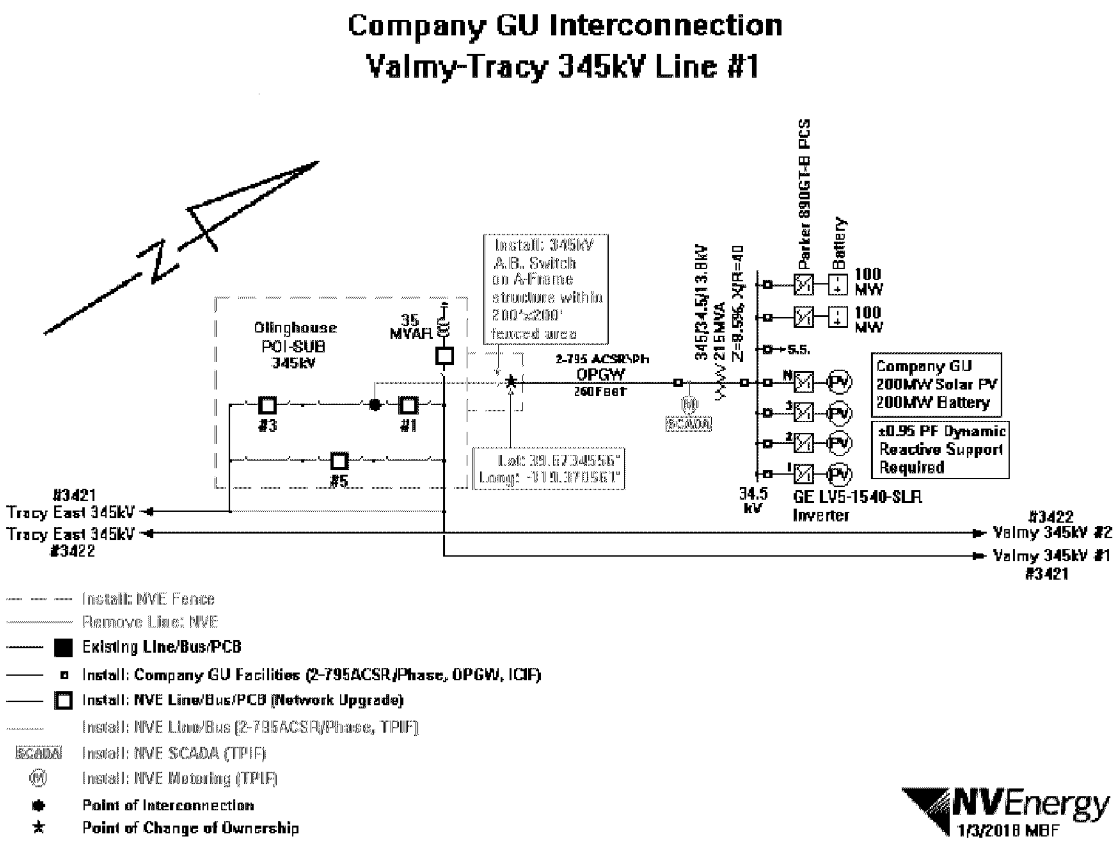
A. DODGE FLAT SOLAR (COMPANY GU) GENERATOR INTERCONNECTION

NextEra Energy ("NextEra") has requested Sierra provide interconnection and necessary network upgrades to support the addition of its Dodge Flat Solar project, a 200 MW solar PV generating facility at the new Olinghouse 345 kV Substation. The new Olinghouse Substation will tap the #3421 line, a 345 kV transmission line between the existing East Tracy and North Valmy 345 kV substations. The project also includes up to 200 MW of battery storage capability, for a maximum of 200 MW delivered Olinghouse. This NextEra project was selected as part of the Companies' renewable RFP. The Large Generator Interconnection Agreement ("LGIA") for this project is included in the Technical Appendix Item TRAN-2.

Construction Scope: Sierra will construct the new Olinghouse 345 kV Substation in a 3-breaker ring configuration 11.2 miles out of East Tracy on the #3421 line between East Tracy and North

Valmy 345 kV substations including the required communication, metering and system protection facilities. Figure TP-25 below depicts a single line diagram of the proposed project.

FIGURE TP-25
ONE LINE DIAGRAM OF DODGE FLAT SOLAR (COMPANY GU) GENERATION INTERCONNECTION



Budget and Cost Responsibility: Customer NextEra is responsible for the cost of building its generator and associated interconnection facilities, including required communications, protections and metering facilities. Sierra is responsible for the cost associated with Network Upgrades, per the OATT, which include the new Olinghouse 345 kV Substation in a three breaker ring configuration, and the required communications for the substation, with an estimated cost of approximately $12.565 million. Projected cash flows for the project are shown in Figure TP-26 below:

FIGURE TP-26
PROJECTED CASH FLOWS FOR DODGE FLAT SOLAR GENERATION INTERCONNECTION

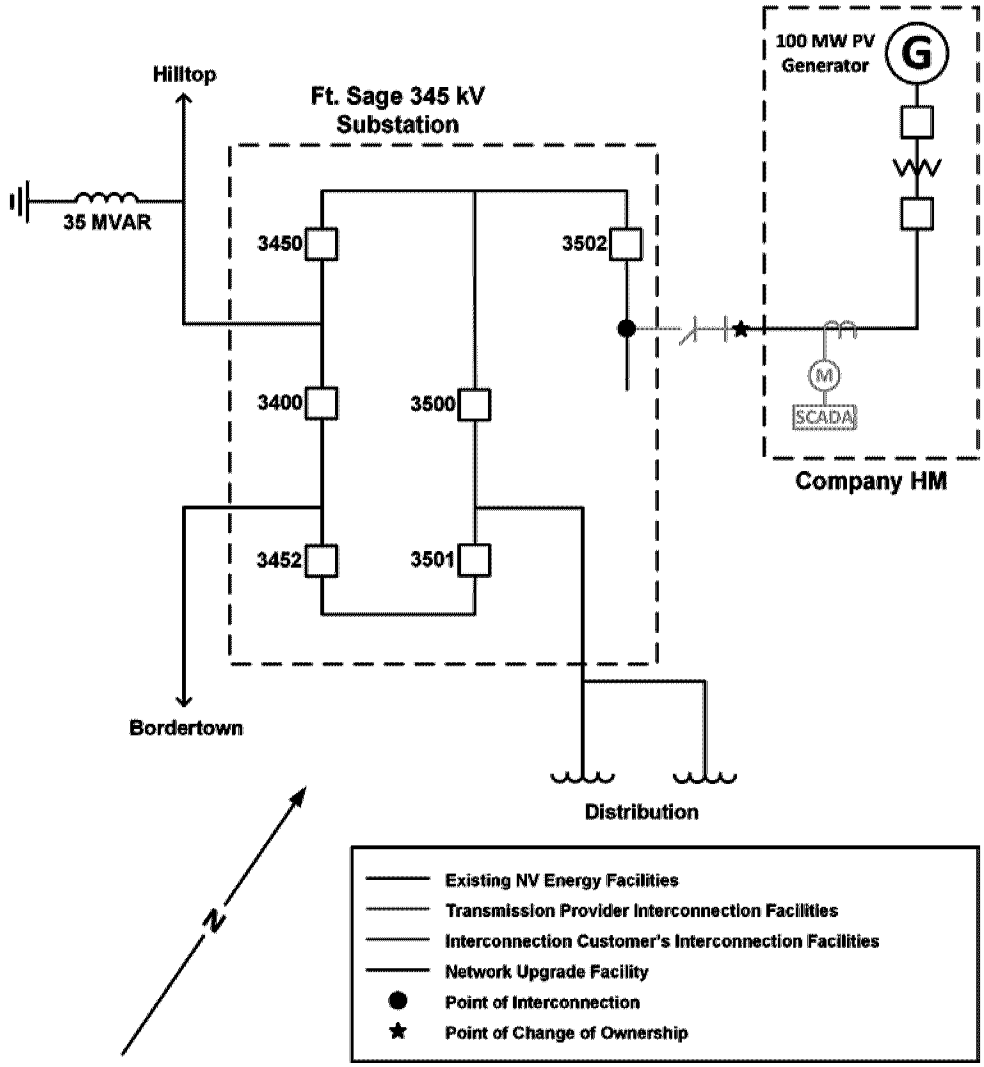
Dodge Flat Solar (Company GU) Network Upgrades Cash Flow						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total** (2018-2020)	**Post 2020**
$ 12,565,000	$ 0	$ 900,000	$ 8,500,000	$ 3,165,000	$ 12,565,000	$ 0

b. Fish Springs Ranch (Company HM) Generator Interconnection

NextEra has requested Sierra provide interconnection and necessary network upgrades to support the addition of its Fish Springs Ranch Project, a 100 MW solar PV facility, at Fort Sage 345 kV Substation and up to 25 MW of battery storage, not to exceed 100 MW delivered at Fort Sage. NextEra submitted this project as part of the Companies' renewable RFP. The facilities study for this project is included in the Technical Appendix Item TRAN-3.

Construction Scope: Sierra will construct a new terminal at the existing Fort Sage 345 kV substation, necessary to accommodate the Fish Springs Ranch interconnection. A single line diagram of the proposed interconnection is shown in Figure TP-27 below:

FIGURE TP-27
ONE LINE DIAGRAM OF FISH SPRINGS RANCH (COMPANY HM) GENERATION INTERCONNECTION



Budget and Cost Responsibility: NextEra is responsible for the cost of building it generator and the associated required interconnection facilities. Sierra is responsible for the cost associated with Network Upgrades, per the OATT. The estimated cost for Sierra to add a terminal at Fort Sage 345 kV substation is $2.38 million. A three-year cash flow has yet to be determined as NextEra has not yet entered into a LGIA with Sierra.

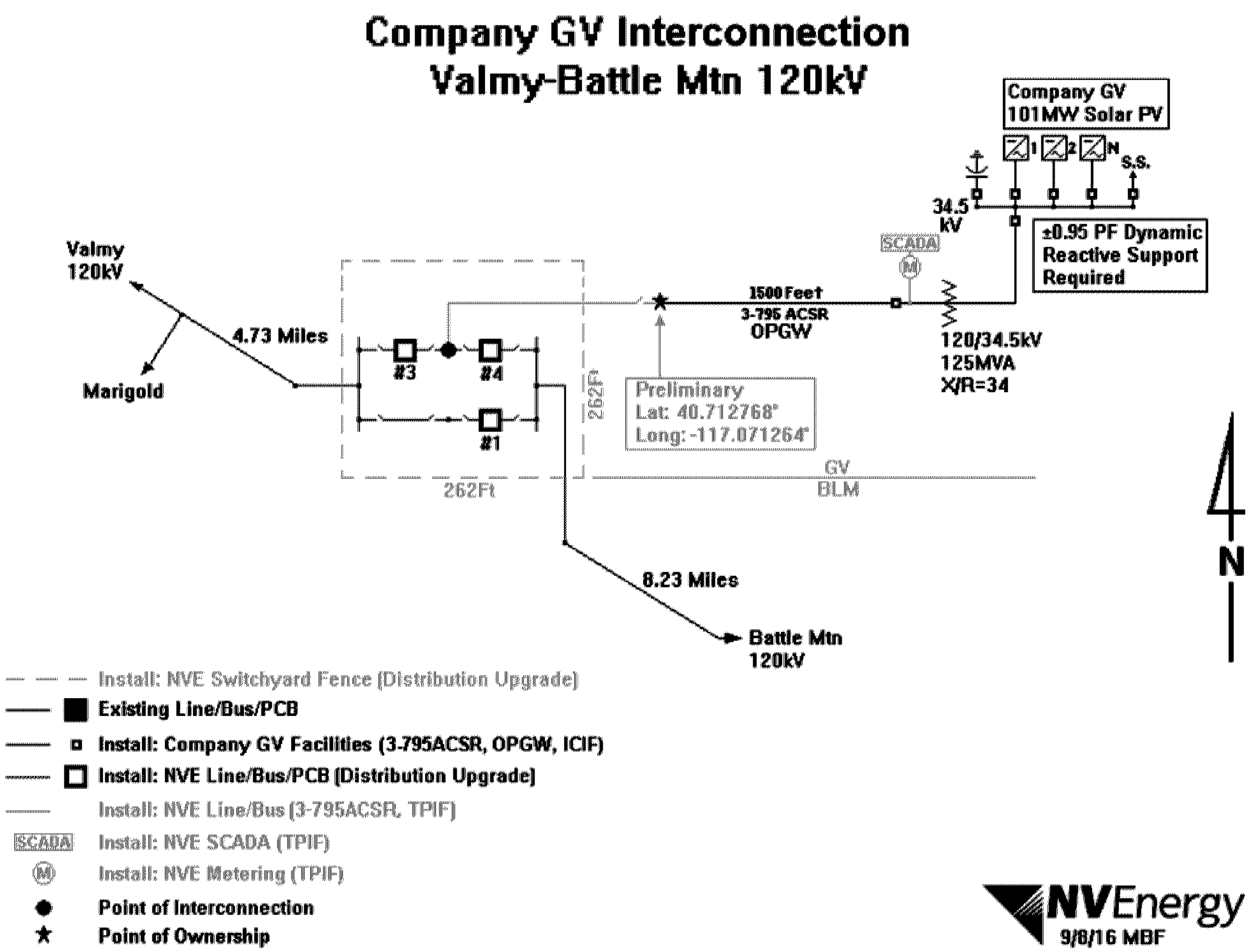
c. BATTLE MOUNTAIN SOLAR (COMPANY GV) GENERATOR INTERCONNECTION

Cypress Creek has requested Sierra provide interconnection and necessary network upgrades to support the addition of the Battle Mountain Solar 101 MW solar PV facility, interconnection request at the new Izzenhood 120 kV substation on the 120 kV #120 line between North Valmy

and Battle Mountain, with up to 25 MW of battery storage, not to exceed 101 MW delivered at Izzenhood. Cypress Creek submitted its project as part of the Companies' renewable RFP. This project remains in the Generator Interconnection Queue at its current position, and has gone into suspension as of October 2017. Cypress Creek can elect to come out of suspension and continue with the project at any point before October 2020. The LGIA for this project is included in the Technical Appendix Item TRAN-4.

Construction Scope: All upgrades for this project are classified as distribution and 100 percent customer funded. There are no Network Upgrade costs for Sierra to accommodate this Interconnection. Cypress Creek is responsible for the costs associated with the new 120 kV substation and the facilities to interconnect to Sierra's system, which include building the new 120 kV Izzenhood Substation between the existing Battle Mountain and Valmy 120 kV substations, and associated cost associated with required communications, protections, metering and permitting. A single line diagram of the proposed interconnection in shown in Figure TP-28 below:

FIGURE TP-28
ONE LINE DIAGRAM OF BATTLE MOUNTAIN SOLAR (COMPANY GV) GENERATION INTERCONNECTION



Budget and Cost Responsibility: The customer is responsible for the cost of building their generator and associated interconnection facilities. Sierra is responsible for the cost associated with Network Upgrades, per the OATT. There are no costs for Sierra to provide interconnection to the transmission system.

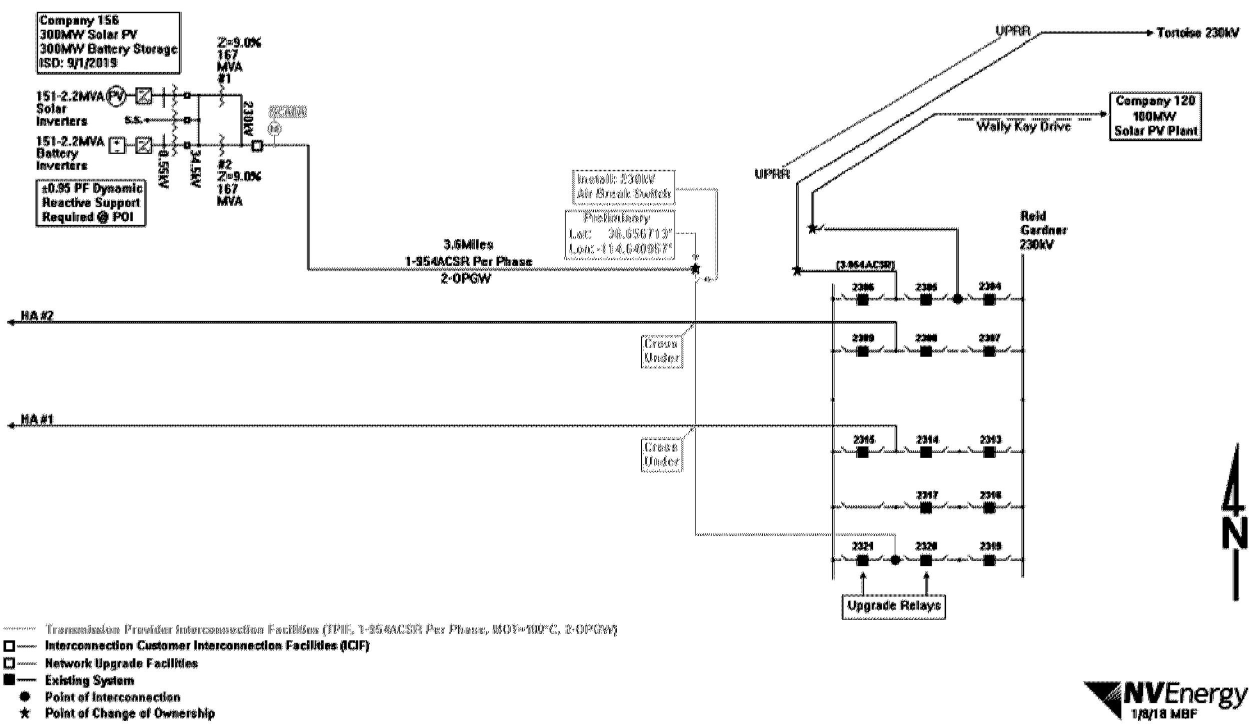
Cypress Creek has requested suspension of this project. Cypress Creek has three years, until October 2020 to request to come out of suspension and continue with the Interconnection, or they forfeit their interconnection queue position, per the Companies' OATT process.

d. **EAGLE SHADOW MOUNTAIN SOLAR FARM (COMPANY 156) GENERATOR INTERCONNECTION**

8minutenergy has requested Nevada Power provide interconnection and necessary network upgrades to support the addition of its 300 MW of solar PV facility and up to 300 MW of battery storage, for a maximum of 300 MW delivered at Reid Gardner 230 kV Substation. 8minutenergy submitted this project as part of the Companies' renewable RFP. The System Impact Study for this project is included in the Technical Appendix Item TRAN-5.

Construction Scope: Nevada Power will provide the required interconnection substation upgrades, communication, metering and system protection facilities at Reid Gardner 230 kV Substation. 8minuteenergy is responsible for the facilities required to interconnect with Nevada Power, including protection, metering and telecommunications. This interconnection is referred to as Company 156 in the single line diagram of the Interconnection in Figure TP-29 below:

FIGURE TP-29
ONE LINE DIAGRAM OF EAGLE SHADOW MOUNTAIN SOLAR FARM (COMPANY 156) GENERATION INTERCONNECTION



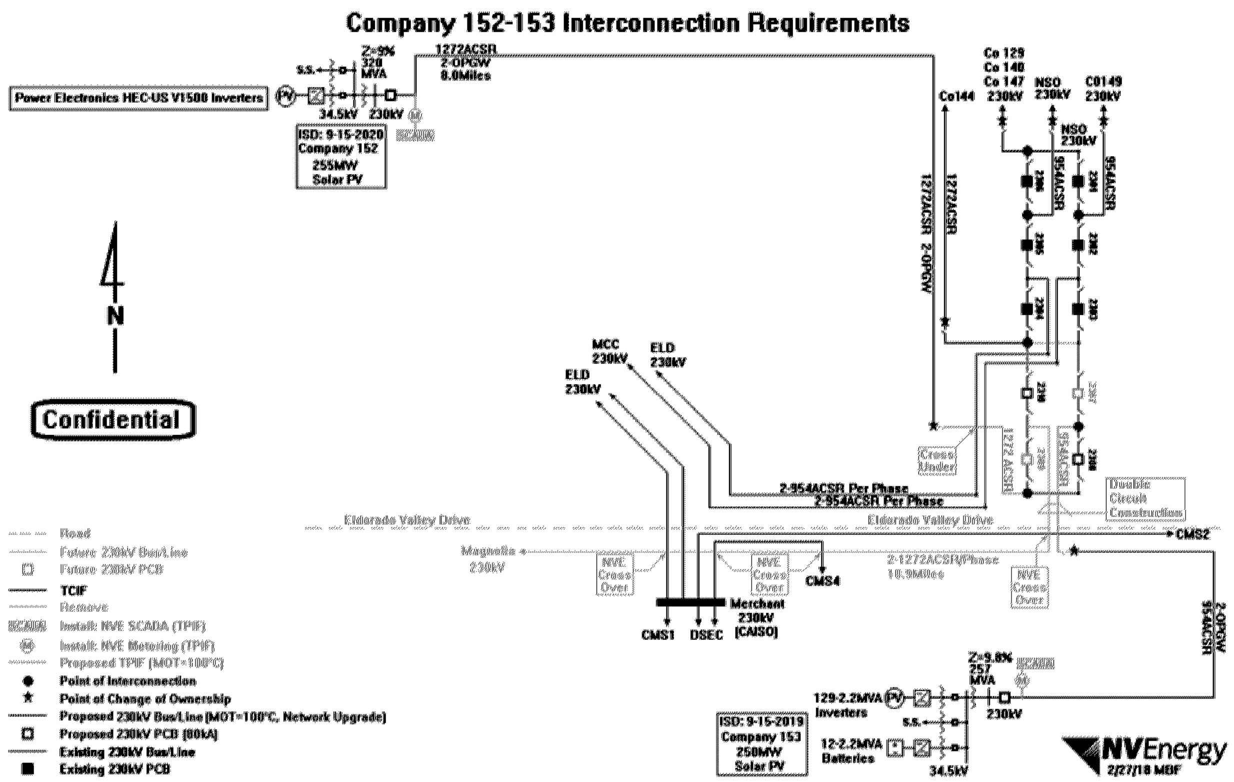
Budget and Cost Responsibility: The customer is responsible for the cost of building its generator and the associated required interconnection facilities. Nevada Power is responsible for the cost associated with Network Upgrades, per the OATT. The estimated cost for the Network Upgrades is projected to be approximately $550,000 with annual cash flow as yet to be determined pending the customers execution of a LGIA.

e. COPPER MOUNTAIN 5 (COMPANY 153) SOLAR GENERATOR INTERCONNECTION

Sempra has requested Nevada Power provide interconnection and necessary network upgrades to support the addition of 250 MW of solar PV generation and up to 20 MW of battery storage, for a maximum of 250 MW delivered at the existing Nevada Solar One 230 kV Substation. Sempra submitted this project as part of the Companies' renewable RFP. The Facilities Study for this project is included in the Technical Appendix Item TRAN-6

Construction Scope: Nevada Power identified Network Upgrades in the Facilities Study to accommodate the interconnection of Sempra's Copper Mountain 5 project, including an expansion of the existing Nevada Solar One 230 kV Substation to a 10-breaker ring configuration, a new terminal position at Nevada Solar One 230 kV and associated interconnection facilities, including communications and land permitting support, with a cost of approximately $7.44 million. Sempra is responsible for the facilities required to interconnect with Nevada Power, including their generator, and required system protection and metering components. A single line diagram of the proposed interconnection is shown in Figure TP-30 below.

FIGURE TP-30
ONE LINE DIAGRAM OF COPPER MOUNTAIN 5 (COMPANY 153)
GENERATION INTERCONNECTION



Budget and Cost Responsibility: Sempra is responsible for the cost of building its generator and associated interconnection facilities. Nevada Power is responsible for the cost associated with Network Upgrades, per the OATT, which for this project are expected to total approximately $7.44

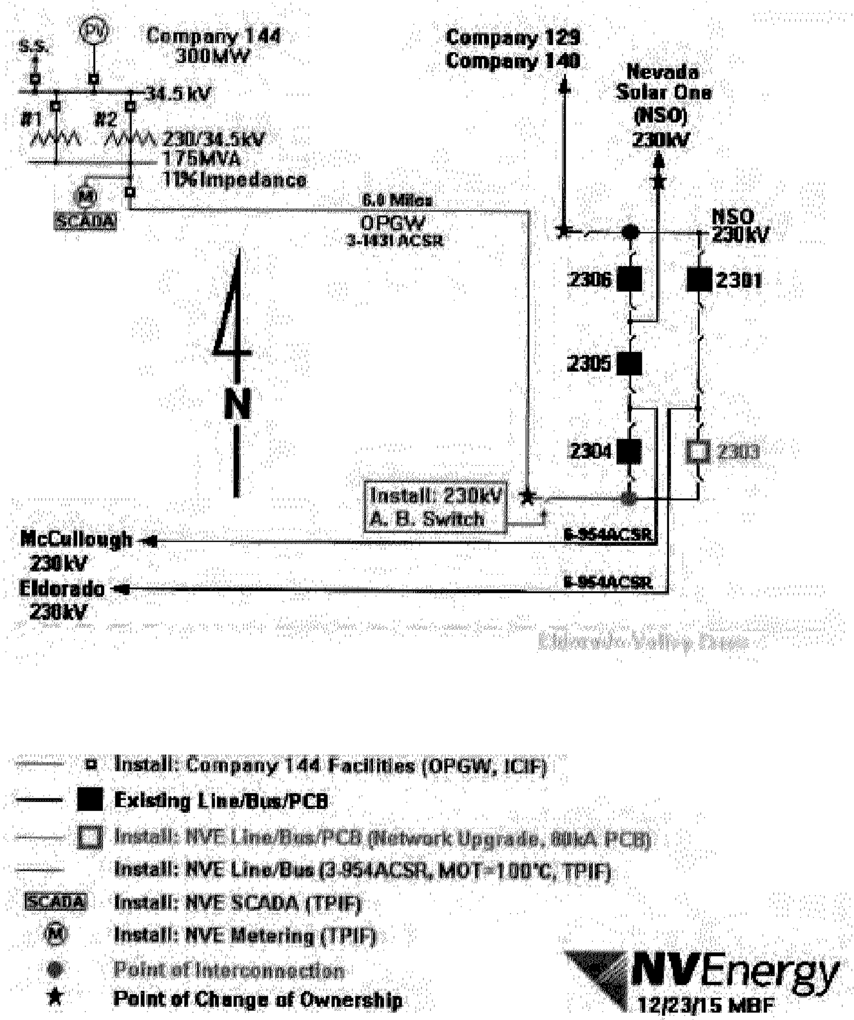
million. This includes expansion of Nevada Solar One 230 kV Substation to 10-breaker ring configuration, the terminal positions, moving existing terminal positions to accommodate the new terminal positions, and additional associated interconnection requirements. The projected cash flows for this have not yet been established

f. TECHREN V (COMPANIES 144 & 152) SOLAR GENERATOR INTERCONNECTION

174 Power Global has requested Nevada Power provide interconnection and necessary network upgrades to support the addition of 50 MW of solar PV generation delivered at the existing 230 kV Nevada Solar One Substation. 174 Power Global submitted its project as part of the Companies' renewable RFP. The LGIA for Techren V as Company 144 is included in the Technical Appendix TRAN-7, and the additional 50 MW request as part of Company 152, can be referenced in the Technical Appendix TRAN-6.

Construction Scope: Nevada Power does not have any obligation to construct network upgrades for this generation addition. 174 Power Global has an existing terminal position currently utilized for its Techren I project, for the project described under Company 144, to which 50 MW of the 255 MW capacity requested under Company 152 will be added. This will require no additional Network Upgrades. A single line diagram of the proposed generator interconnection is shown in Figure TP-31 below.

FIGURE TP-31
ONE LINE DIAGRAM OF TECHREN V (COMPANY 144) GENERATION INTERCONNECTION



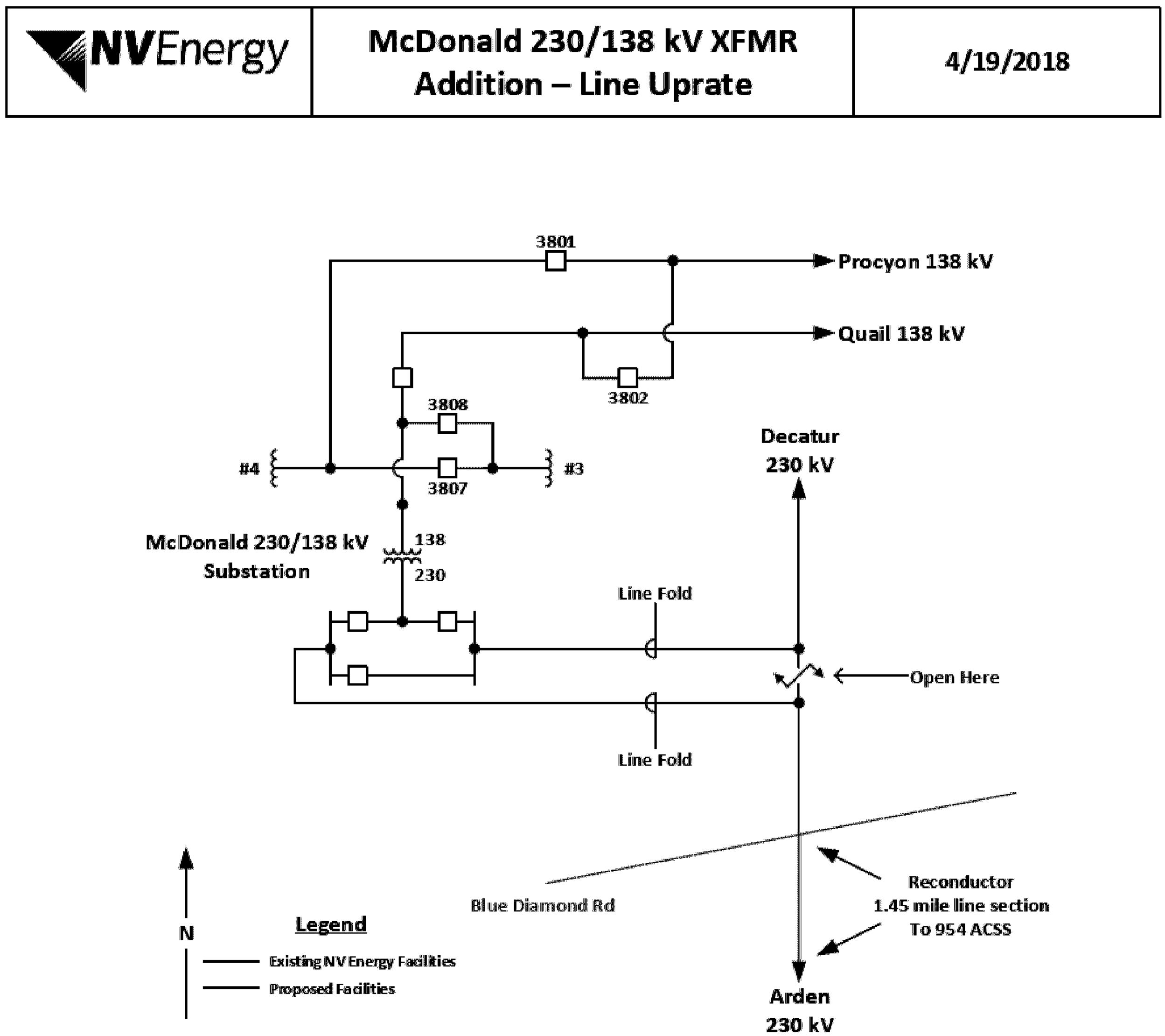
Budget and Cost Responsibility: 174 Global Power is responsible for the cost of building its generator and associated required facilities for interconnection, including communications, and system protections. Due to the utilization of the existing generator terminal, Nevada Power does not have any Network Upgrade costs associated with this project, per the OATT requirements.

g. LINE UPGRADE FOR SECTION OF ARDEN TO MCDONALD 230 KV LINE

As a result of the previously approved McDonald 230/138 kV Substation upgrade, a 1.45 mile section of the Arden to McDonald 230 kV line is required to be upgraded to mitigate potential TPL-001-4 violations under contingency conditions. The study providing technical details on this project is included in the Technical Appendix Item TRAN-8.

Construction Scope: Nevada Power is proposing to upgrade a 1.45 mile section of the 230 kV line between Arden and McDonald substations, from the existing 954 ACSR conductor to 954 ACSS conductor, in order to mitigate overloads on the section caused by P1 contingency events. A single line diagram showing the proposed upgrades are shown below in Figure TP-32.

FIGURE TP-32
ONE LINE DIAGRAM OF ARDEN TO MCDONALD 230 KV LINE UPGRADE



Budget and Cost Responsibility: Nevada Power is proposing to include the required line upgrade at a cost of approximately $720,000 with the McDonald 230/138 kV Transformer addition. The three year cash flow for the line upgrade project is shown below in Figure TP-33.

FIGURE TP-33
PROJECTED CASH FLOWS FOR THE ARDEN TO MCDONALD LINE UPGRADE

Arden to McDonald 230 kV Line Upgrade						
Project Total	**Pre-2018**	**2018**	**2019**	**2020**	**3 Year Total (2018-2020)**	**Post 2020**
$ 720,000	$ -	$ 720,000	$ -	$ -	$ 720,000	$ -

11. WESTCONNECT MEMBERSHIP

Per NAC § 704.9385(3)(f), the Companies are required to describe their participation in regional planning organizations, as well as the role of these organizations in the Companies' transmission planning activities. The Companies are requesting permission to continue participation in WestConnect with funding of approximately $225,000 distributed equally over the three year Action Plan period, as shown in Figure TP-34 below:

The Companies have participated in transmission planning activities associated with WestConnect since the 2015 formation of the organization, pursuant to the requirements laid forth in FERC Order No. 1000. WestConnect has a FERC-approved Planning Participation Agreement setting forth the rights and obligations of members who pay dues to WestConnect, stakeholders who participate in WestConnect open activities, and the Planning Management Committee that steers WestConnect.

FIGURE TP-34
WESTCONNECT MEMBERSHIP DUES (IN THOUSANDS)

	2019	**2020**	**2021**	**2019-2021** (3-Year Total)
NV Energy	**$225**	**$225**	**$225**	**$675**
TOTAL	**$225**	**$225**	**$225**	**$675**

12. TRANSMISSION LOSSES

NAC § 704.9385(3)(h) requires the Companies include in its Transmission Plan a description of efforts to reduce the impact of line losses on future resource requirements. The Companies' efforts to evaluate and mitigate line losses are ongoing. Line losses are calculated into the overall plan of service for load growth, selection of company-owned generation, independent power producer development, and renewable energy evaluations in order to develop the most cost effective facilities (*i.e.*, the impact of losses is evaluated in those cases where the Companies have the ability to select from various options).

13. RENEWABLE ENERGY ZONE TRANSMISSION PLAN

In response to the requirements provided for in NAC § 704.9385(6) and NAC § 704.9489(5), regarding the development of transmission facilities to serve renewable energy zones within the State of Nevada, the Companies have prepared a Conceptual Renewable Energy Zone Transmission Plan ("REZTP" or "Plan").

The REZTP is a conceptual plan for transmission facilities that shows possible transmission access to areas of Nevada that have been designated as renewable energy zones. The REZTP does not request any funds construction nor does it request Commission approval of any facilities associated with the REZTP.
The Companies did not produce new studies for the REZTP for this filing. There has been no interest by any parties outside the Companies to pursue any studies with respect to this plan. Upon a new identification of renewable energy zones by the Commission, or new interest by outside parties, the Companies will revisit the REZTP and update accordingly. Additional details on the REZTP are provided in the Technical Appendix Item TRAN-9.

14. FEDERAL REGULATORY FILINGS

NAC § 704.9385(3)(g) requires the Companies include in the Transmission Plan a summary of the impacts of relevant orders issued by FERC since the last IRP, Docket No. 16-07001. The following information is provided in compliance with that requirement.

a. FERC ORDERS

Order No. 827: Reactive Power Requirements for Non-Synchronous Generation
FERC is eliminating the exemptions for wind generators from the requirement to provide reactive power by revising the pro forma LGIA, Appendix G to the pro forma LGIA, and the pro forma Small Generator Interconnection Agreement ("SGIA"). As a result, all newly interconnecting non-synchronous generators will be required to provide reactive power at the high-side of the generator substation as a condition of interconnection as set forth in their LGIA or SGIA as of the effective date of this final rule.

The Companies revised their OATTs, specifically the LGIA and SGIA to comply with FERC Order 827. In response to the amendments, FERC issued docket No. ER17-27 accepting the Companies' compliance filing with Order No. 827.

Order No. 828: Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities
FERC is modifying the pro forma SGIA. The pro forma SGIA establishes the terms and conditions under which public utilities must provide interconnection service to small generating facilities of

no larger than 20 megawatts. FERC is modifying the pro forma SGIA to require newly interconnecting small generating facilities to ride through abnormal frequency and voltage events and not disconnect during such events. The specific ride through settings must be consistent with Good Utility Practice and any standards and guidelines applied by the transmission provider to other generating facilities on a comparable basis. FERC already requires generators interconnecting under the LGIA to meet such requirements, and it would be unduly discriminatory not to also impose these requirements on small generating facilities. FERC concluded that newly interconnecting small generating facilities should have ride through requirements comparable to large generating facilities.

The Companies revised the OATT attachments N and O in order to fulfill the compliance requirements of Order No. 828. In response to the amendment, FERC issued docket No. ER17-27 accepting the Companies compliance with Order No. 828.

Order No. 842: Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response

FERC is revising its regulations to require newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. To implement these requirements, FERC is modifying the pro forma LGIA and the pro forma SGIA. These changes are designed to address the potential reliability impact of the evolving generation resource mix, and to ensure that the relevant provisions of the pro forma LGIA and pro forma SGIA are just, reasonable, and not unduly discriminatory or preferential.

The Companies are in the process of updating the OATT in order to meet compliance with this order. The updates are expected to be filed with FERC under the appropriate timeline to meet full compliance with the order.

b. RULEMAKING ORDERS

The Companies continue to follow, comment upon, and monitor FERC rule making dockets in order to meet or maintain compliance with the orders, including each of the following:

RM16-17-000: Data Collection for Analytics and Surveillance and Market-Based Rate Purpose

Berkshire Hathaway Energy Company ("BHE") filed comments in RM16-17 "Collection of Connected Entity Data from Regional Transmission Organizations and Independent System Operators and Ownership Information in Market-Based Rate Filings." BHE has serious concerns about the proposed requirement to disclose commonly-owned affiliates that do not have an independent reporting obligation to FERC, as well as the potentially broad definition of "trader," and multiple clarifications needed in the data dictionary. The final rule should clarify that a

reporting entity will not be required to obtain EIA Plant Codes for plants that are not required to be reported under EIA-860, such as plants with less than 1 MW combined nameplate capacity. Also, NV Energy believes the final rule needs to address how confidentiality will be maintained in response to requests under the Freedom of Information Act ("FOIA"), and what standard FERC will apply in considering whether to grant a request under FOIA.

RM-05-5-025: Standards for Business Practices and Communication Protocols for Public Utilities FERC is proposing to incorporate by reference the latest version (Version 003.1) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant of the North American Energy Standards Board (NAESB). These standards mainly modify and update NAESB's WEQ Version 003 Standards. The Commission also proposes to revise its regulations to incorporate NAESB's updated Smart Grid Business Practice Standards in the Commission's General Policy and Interpretations.

RM16-6-000: Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response

FERC is proposing to revise its regulations to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection. To implement these requirements, FERC proposes to revise the pro forma LGIA and the pro forma SGIA, to address the increasing impact of the evolving generation resource mix and to ensure that the relevant provisions of the pro forma LGIA and pro forma SGIA are just, reasonable, and not unduly discriminatory or preferential. FERC is also seeking comments on whether its proposals in this Notice of Proposed Rulemaking are sufficient at this time to ensure adequate levels of primary frequency response, or whether additional reforms are needed.

RM-17-8-000: Reform of Generator Interconnection Procedures and Agreements
FERC is proposing to revise its regulations and the pro forma Large Generator Interconnection Procedures and pro forma LGIA. FERC reforms are designed to improve certainty, promote more informed interconnection, and enhance interconnection processes. The proposed reforms are intended to ensure that the generator interconnection process is just and reasonable and not unduly discriminatory or preferential.

15. TRANSMISSION TECHNICAL APPENDICES

The following transmission-related information is set forth in the Technical Appendix volume as:

- Technical Appendix TRAN-1: Timing of new Transmission Sources for SPPC
- Technical Appendix TRAN-2: Dodge Flat Solar LGIA
- Technical Appendix TRAN-3: Fish Springs Ranch Facilities Study
- Technical Appendix TRAN-4: Battle Mountain Solar LGIA

Technical Appendix TRAN-5: Eagle Shadow Mountain Solar Farm System Impact Study
Technical Appendix TRAN-6: Copper Mountain 5 Facilities Study
Technical Appendix TRAN-7: Techren V LGIA
Technical Appendix TRAN-8: Arden to McDonald 230 kV Line Uprate
Technical Appendix TRAN-9: Renewable Energy Zone Transmission Plan

F. DISTRIBUTION PLANNING

1. INTRODUCTION

NRS § 704.741(3)(c), as amended by Senate Bill ("SB") 374 (2015 Legislature), asked the Commission to require Nevada Power and Sierra to include in their integrated resource plans the effect of Net Metering Systems, as that term is defined in NRS § 704.766 to 704.775, inclusive, on the reliability of the their distribution systems. The Companies first addressed the 2015 Legislature's question in Volume 10 (Supply Side Plan) of Sierra's IRP filed in Docket No. 16-07001. There, Sierra indicated that the Companies had not experienced an identifiable effect on distribution system reliability, either positive or negative, due to the presence of installed Net Metering Systems.

The 2017 Legislature amended NRS § 704.741(3)(c) slightly, clarifying that a discussion of the impact of Net Metering Systems on the Companies' respective distribution systems should be included in this Joint IRP. As is set forth below, at current penetration levels[33], the Companies have yet to identify discernable effects, either positive or negative, of Net Metering Systems on the reliability of their distribution systems. However, with the introduction of energy storage paired with private solar PV installations to the Net Metering System program, impacts may quickly become observable if such systems provide back-up service to customer load during outage conditions on the Companies' distribution systems.

2. DISTRIBUTION SYSTEM RELIABILITY

Reliability can be viewed from both the utility and customer perspectives.

a. UTILITY PERSPECTIVE-POSITIVE EFFECTS

The reliability of electric utility distribution systems from the utility perspective is typically measured through the use of indices based on the Institute of Electrical and Electronics Engineers ("IEEE") Standard 1366. Those indices are well known and tracked by the Commission in other contexts and include:

[33] As of April 30, 2018, there were a total of 28,695 premises with Net Energy Metering installations, representing 253.5 MW of capacity on the Companies' distribution systems.

- System Average Interruption Frequency Index ("SAIFI")
- System Average Interruption Duration Index ("SAIDI")
- Customer Average Interruption Duration Index ("CAIDI")

The Companies regularly track and report their performance on these indices to the Commission. One of the basic measures feeding into the aforementioned indices is Customer Minutes of Interruption ("CMI"). In order for the presence of Net Metering Systems to have a positive impact on distribution system reliability from the utility perspective, CMI on specific distribution feeders serving NEM customers would have to be reduced during an outage as a result of the existence of the Net Metering Systems on those feeders.

Both the Companies' and industry interconnection standards and rules affect how Net Metering Systems must operate under outage conditions. The Companies' Rule 15 (Generating Facility Interconnections) describes the interconnection, operation, and metering requirements for generating facilities with a capacity of 20 MW and less that are intended to be connected to (paralleled with) the Companies' distribution systems. Net Metering Systems as defined in Nevada Revised Statute ("NRS") § 704.771, are subject to Rule 15, but are not subject to many of the design and operating requirements in Section E of Rule 15. In particular, Rule 15 Section E.1.a. states:

> *a. The requirements of this Section E do not apply to Net Metering Systems as such systems are defined in Nevada Revised Statutes 704.766 to 704.775. Net Metering Systems shall meet all of the requirements of:*
>
> *(1) The National Electric Code,*
> *(2) Underwriters Laboratories Inc., and*
> *(3) Institute of Electrical and Electronics Engineers with IEEE Standards 929 and 1547 having particular application. The optional and lockable disconnects of IEEE 1547 are required.*

Consequently, Net Metering Systems on the Companies' distribution systems are subject to the requirements of IEEE Standard 1547. Several provisions in the updated version of IEEE Standard 1547[34] prohibit distributed energy resources, including Net Metering Systems, from energizing the utility distribution system during abnormal operating conditions, as follows:

[34] IEEE 1547-2018, approved February 15, 2018 and issued earlier this year.

4.9 Inadvertent energization of the Area EPS
The DER shall not energize the Area EPS when the Area EPS is de-energized. Exceptions may be given for intentional Area EPS islands per 8.2 at the discretion of the Area EPS operator.[35]

6.2.1 Area EPS faults
For short-circuit faults on the Area EPS circuit section to which the DER is connected, the DER shall cease to energize and trip unless specified otherwise by the Area EPS operator. This requirement shall not be applicable to faults that cannot be detected by the Areas EPS protection systems.

and

8.1 Unintentional islanding
8.1.1 General
For an unintentional island in which the DER energizes a portion of the Area EPS through the PCC[36]*, the DER system shall detect the island, cease to energize the Area EPS, and trip within 2 seconds of the formation of an island.*

As a result of the above requirements, during outages on the Companies' distribution systems, Net Metering Systems must be isolated from the utility's electric system. This requirement can, however, be circumvented only if the utility has provided pre-existing approval for the formation of an intentional island, which is allowable per the IEEE 1547-2018 standard.[37] To date, such approval has not been requested by a customer with a NEM system, nor has permission been granted by the Companies.

The operating practice of ensuring that distributed generation systems disconnect from the electric utility system under outage conditions was established in the industry many years ago to ensure the safety of utility personnel and the public. Consequently, under outage conditions, from the utility perspective of SAIDI, SAIFI, or CAIDI, the NEM customer is out of service and contributes to CMI.

b. CUSTOMER PERSPECTIVE-POSITIVE EFFECTS

From the customer perspective, however, Net Metering Systems, especially those with modern smart inverters, can be designed to operate in a back-up mode, operating isolated from the distribution system during an outage. Such back-up operation could allow the NEM system to

[35] EPS means Electric Power System; DER means Distributed Energy Resource.

[36] PCC in this context means Point of Common Coupling.

[37] Section 8.2 of IEEE 1547-2018.

provide electric service to either the customer's total load or a designated critical portion thereof. However, given that the Companies do not have operational visibility (meaning, remote real-time or near real-time visibility) into the status and operation of the Net Metering Systems, the Companies do not presently have the ability to identify the NEM customers whose total load (or portion of total load) might remain energized due to the NEM system operating in a back-up mode. Neither can the Companies identify the amount of time those customers' load may remain either wholly or partially energized during an outage (during which NEM customers might continue to receive power from their installed Net Metering Systems while isolated from the Companies' distribution system).[38] This information would be essential to quantify any reduction in CMI that might occur due to customers having installed Net Metering Systems, and therefore, quantifying any improvement in reliability from the customer perspective. Additionally, these Net Metering Systems are not integrated with the Companies' Advanced Distribution Management, Outage Management, or Energy Management Systems, which is also critical to understanding the effect of Net Metering Systems during an outage.

In order for Net Metering installations and other Distributed Energy Resources ("DER") to have a known and measureable positive effect on distribution reliability as measured by the aforementioned industry standard indices, they must be available when needed, sited properly, and visible to the utility, and governing industry and utility standards must safely allow such operation.

c. NEGATIVE EFFECTS

Conversely, the Companies have yet to determine that distribution system reliability has been negatively affected as a direct result of the presence of Net Metering and other DER on distribution feeders. Nevertheless, several areas of concern do arise with regard to their effect on the reliability of the electric distribution system should penetration levels increase significantly and/or clustering occur in the future. Volume 2 of the Companies' initial filings in Docket Nos. 15-07041 and 15-07042 outlined a number of these potential concerns with respect to thermal overload, voltage, power factor, protection and control, operational switching, management and operation of distribution equipment, and monitoring and tracking systems.[39] If NEM penetration levels were to increase significantly, the likelihood of negative effects on the reliability of the distribution system could increase as a consequence of Net Metering Systems coincidentally disconnecting from or reconnecting with the distribution system (*e.g.,* for PV systems due to sudden cloud cover) without proper monitoring and control systems in place to effectively

[38] Because telemetering is not required or installed on NEM installations under 250 kVA, which represent the vast majority of installed Net Metering Systems.

[39] Docket No. 15-07041, Volume 2 Narrative, pgs. 77-78 of 187; and Docket 15-07042, Volume 2 Narrative, pgs. 74-75 of 175.

manage the collective loss of energy generating resources and integration with one or more of the Companies' aforementioned operating systems.

Assuming an operating environment with significant penetration and/or clustering, reinforcement of the distribution system coupled with modernization of the grid would be essential to maintain satisfactory levels of reliability. Strategic, locational deployment of Net Metering Systems through targeted marketing efforts could serve to direct such installations to areas of the distribution system with a greater ability to accommodate them before constraints, and therefore mitigation costs, on the system are encountered. However, this strategy would require as a prerequisite the performance of Hosting Capacity studies on the distribution system to identify such areas, other areas of the distribution system with greater constraints (*i.e.*, a lower ability to accommodate a high penetration of NEM), and the proposed mitigation measures (and therefore costs) required to increase the capacity of the distribution system to safely and reliably accommodate NEM installations. Hosting Capacity studies essentially determine a distribution feeder's ability to accommodate DER before a constraint is encountered, and involve modeling DER generation and load at various capacity levels and different locations on the feeder. Examples of such constraints can be thermal overload of conductors or equipment, excessive voltage rise, or system protection mis-coordination. The Companies expect to begin performing Hosting Capacity studies later this year in support of the requirement to file a Distributed Resource Plan ("DRP") as an amendment to this joint IRP no later than April 1, 2019.

d. EFFECTS ON THE INTEGRATED SYSTEM

While NRS § 704.741(3)(c) focuses on the reliability of the utilities' distribution systems, the issue of the potential impacts of Net Metering Systems in particular, and DER in general, both positive and negative, are not limited to the distribution system alone. Impacts on the transmission and energy supply systems may be experienced should penetration levels eventually become high enough. This will prompt studies to be performed to determine the impacts to operations, maintenance, generation fleet dispatch, fuel cost, imports & exports, ramp rates, and the need for ancillary services affecting those systems.

3. DISTRIBUTED RESOURCE PLANNING

Enacted by the 2017 Nevada Legislature, SB 146, Section 1, modified NRS § 704.741 to require the Companies to file a DRP, while Section 3.2 of the bill established that the DRP must be filed on or before April 1, 2019 as an amendment to the joint IRP.

Since the passage of SB 146, the Companies have been working internally, with industry stakeholders, and with the Commission to develop the components of what will be Nevada's first DRP, ensuring compliance with Section 1 of SB 146, which includes requirements to:

- Evaluate the locational benefits and costs of DERs,
- Propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective DERs,
- Propose cost-effective methods of effectively coordinating existing programs approved by the Commission, incentives and tariffs to maximize the locational benefits and minimize the incremental costs of DERs,
- Identify any additional spending necessary to integrate cost-effective DERs into distribution planning consistent with the goal of yielding a net benefit to the customers of the electric utility or utilities, and
- Identify barriers to the deployment of DERs, including, without limitation, safety standards related to technology or operation of the distribution system in a manner that ensures reliable service.

For informational purposes, the Companies are presently considering the following distribution planning elements be included in the DRP:

- Load and DER Forecasting
- Hosting Capacity Analysis
- Locational Net Benefits Analysis
- Grid Needs Assessment, and
- Interconnection

Further, the Companies are also considering the following topics be contained within the DRP (subject to continual refinement):

- DRP Policy and Vision
- Stakeholder Engagement
- Distribution System Planning
- Transmission and Distribution Project Deferral
- Interconnection
- Tariffs and Programs
- Barriers to Deployment of DERs
- Pilots and Demo Projects
- Data Sharing and Access
- Integration with IRP and other Legislative Actions
- Investment Plans and Budget, and
- Phasing of Next Steps

The Companies continue to work with stakeholders to define, refine, and evolve the analytical methods that will be used in development of the DRP, the aforementioned elements and topics, as well as proposed changes to regulations that will establish the essential components of the DRP in more detail than is set forth in SB 146.

SECTION 3. ECONOMIC ANALYSIS

A. OVERVIEW

An economic analysis of different capacity and ESP was conducted and a Preferred Plan was selected from the set of cases. In this section, the following economic analysis topics will be covered:

- The Analysis Methodology
- Key Modeling Assumptions
- Plan Development
- Economic Analysis Results
- Selection of the Preferred and Alternate Plans
- Loads and Resources Tables
- Environmental Externalities and Economic Benefits to the State
- Long-Term Avoided Costs

The Commission's regulations for integrated resource planning serve as the framework for the analysis of the alternative plans set forth in this filing. These include:

- NAC § 704.937:
    - Provide a list of options for supply, including existing and planned options;
    - State the criteria used for the selection of supply options;
    - Compute the present worth revenue requirement ("PWRR") for each case alternative;
    - Compute the present worth of societal cost ("PWSC") for each case alternative;
    - Consider each case alternative for the mitigation of risk;
    - Consider each case alternative for reliability;
    - Ensure each case alternative meets or exceeds the RPS; and
    - List the assumptions used to evaluate the case alternatives.
- NAC § 704.9357: Determination of the net economic benefit to the State.
- NAC § 704.9359: Determination of environmental costs to the State.
- NAC § 704.9465: Integrated analysis to establish priorities among options.
- NAC § 704.9475: Analysis of sensitivity for major assumptions and estimates used.

- NAC § 704.948: Analysis of decisions with respect to mitigating risk, minimizing cost and volatility, and maximizing reliability.

Additionally, pursuant to NAC § 704.952(5) and Senate Bill 65 (2017 legislative session), prior to making any integrated resource plan filing, the Companies meet with the Staff, BCP and any interested persons to present its preliminary key modeling assumptions and to provide an overview of the anticipated filing. This meeting took place December 20, 2018. The materials for this workshop and notice of a public meeting are provided as Technical Appendix Item ECON-1.

B. ANALYSIS METHODOLOGY

Loads & Resources Tables. The Companies' analysis of future resource requirements begins with the Loads and Resources ("L&R") tables. A long-term forecast of annual peak loads, planning reserve requirements, and a forecast of an annual peak capacity for supply-side and demand-side resources are used to determine the Companies' annual open capacity position ("Open Position"). The Open Position is defined as any value resulting from the peak load plus planning reserves being greater than the sum of the peak planning capacities for all of the available supply-side and demand-side resources.

The Companies typically leave some Open Positions to be filled with market purchases for capacity and energy. In any year where there is an Open Position, the Companies assume the ability to secure needed capacity from the electric wholesale market at the forecasted capacity cost for that year. The cost of this capacity is included in the total costs for each plan. A more detailed discussion around the creation and use of the L&R tables is described in the Loads and Resources Section (part G) of this Economic Analysis narrative.

Production Costs and Capital Expense Recovery Models. After developing the L&R tables, the Companies utilizes two economic models to evaluate each plan over the planning period. The first is a production cost model, PROMOD.[40] PROMOD computes overall production cost by performing hourly, chronological economic unit commitment and dispatch of the Companies' electric production resources and market purchases to satisfy load requirements in a least cost solution over the planning period. A more detailed description of PROMOD can be found in Technical Appendix Item ECON-2. There are several key modeling assumptions made in performing PROMOD analysis. These are discussed in more detail in the next section and include but are not limited to:

a) Planning period,

b) Joint system modeling,

c) Area configuration,

[40] PROMOD is a proprietary software product that the Companies license from ABB Group.

d) Hourly load forecast,
e) Market fundamentals,
f) Existing generation operating characteristics (including fixed costs),
g) New generation operating characteristics (including fixed costs),
h) Operating reserves,
i) Renewable energy modeling,
j) Purchase Power Agreements, and
k) Transmission limits.

The second model used to evaluate alternative plans is a spreadsheet workbook called the Capital Expense Recovery model ("CER"). The CER calculates annual revenue requirements associated with capital investments needed to satisfy load requirements during the planning period for each plan. Several key modeling assumptions made in the CER include but are not limited to:

a) Capital costs of new generation,
b) Capital costs of resource acquisitions,
c) Capital costs of transmission projects,
d) Construction cost escalation rates,
e) Cash flow schedules,
f) Allowance for Funds Used During Construction ("AFUDC") estimates,
g) Construction start dates,
h) Project in-service dates,
i) Project book lives, and
j) Project tax lives.

<u>Present Worth of Revenue Requirement.</u> After running PROMOD and the CER, the sum of the annual production costs from PROMOD plus the sum of the annual capital revenue requirement from the CER over the planning period, discounted by each Company's weighted cost of capital, provide the PWRR for the various plans. A comparison of the PWRR of each plan provides a ranking of the cases from least cost to most expensive. This ranking is only one factor used to determine the Preferred Plan. Other factors such as reliability, risk mitigation, and resource diversity are also considered. Each plan is then subjected to scenario analyses where load, market fundamentals, and environmental costs are varied. A PWRR ranking of the plans is determined for each scenario.

<u>Scenario Analysis.</u> NAC § 704.9475 requires the utility to conduct an analysis of sensitivity for all major assumptions and estimates used in the resource plan in addition to the base assumptions.

To satisfy this requirement, the Companies evaluated each plan with sensitivities around a) load forecasts, b) fuel and purchase power price forecasts, and c) carbon price forecasts.

The base assumptions for this filing are a base (or mid-level) load forecast, base (or mid-level) fuel and purchase power price forecast, and a mid-level carbon price assumption. For this filing, the Companies have conducted sensitivities around the load with a high economic growth case, a low economic growth case, and a 704B case – which assumes additional customers in southern Nevada receive authorization from the Commission to utilize a provider of new electric resources under NRS Chapter 704B. The base fuel and purchase power price forecasts have been supplemented with two additional fuel and purchase power price forecasts: high and low fuel and purchase power price forecasts. The mid-level carbon price assumption has been tested with three additional forecasts: high, low, and no carbon price sensitivities. Further details on these forecasts can be found in the Load Forecast and Market Fundamentals volume.

The scenario analysis shows how the PWRR results would change under the different sensitivities. Figure EA-1 below shows the scenarios performed on each plan. In addition to the sensitivities shown in Figure EA-1, the Preferred Plan was subjected to a Base Load, Base Fuel, and mid-carbon scenario with the ability to make off-system sales. The production costs, capital costs, and total PWRR results for all the scenarios run are found in Technical Appendix Items ECON-7 and ECON-8.

FIGURE EA-1:
SENSITIVITIES CONDUCTED FOR ECONOMIC ANALYSIS

Scenario	Load	Fuel	Carbon
1	Base	High	MidC
2*	Base	Base	MidC
3	Base	Low	MidC
4	Base	Base	HighC
5	Base	Base	LowC
6	Base	Base	NoC
7	High	Base	MidC
8	Low	Base	MidC
9	704B	Base	MidC

* Base Assumptions

C. KEY MODELING ASSUMPTIONS

Planning Period. The resource planning regulations specify the calculation of a 20-year PWRR for each plan. Consistent with the Companies' most recent IRP filings, a 30-year PWRR for all plans has also been calculated in order to provide additional color regarding the benefits of plans

that rely on commitments or investments during the Action Plan period that are longer-lived than 17 to 20 years.

Joint System Modeling. All of the analysis is performed using combined system production cost and capital expense recovery models. All reported PWRR results include the total production costs and capital revenue requirements for both systems. The production cost data provided in Technical Appendix Item ECON-8 also list the production costs for the Sierra and Nevada Power systems separately for each plan.

Area Configuration. PROMOD utilizes an area configuration in order to assign resources and load to specific areas and to capture transmission use between areas. The areas may contain both resources and load, or resources only, and are connected to each other to simulate transmission between areas. PROMOD allows for the modeling of transmission to ensure that transmission capacities are not violated. However, it should be noted that PROMOD is not a transmission flow model and the transmission flows determined by PROMOD are based solely on economics. PROMOD outputs do not represent actual physical flows. A graphical depiction of the area configuration used in this filing, along with the area location of each load and asset and the annual maximum transfer between areas, is provided in Technical Appendix Item ECON-10.

Hourly Load Forecast. The Companies' load forecast has been updated from the previously approved forecast in Docket No. 17-11003, Sierra's 2nd Amendment to the 2017-2036 IRP and Docket No. 17-11004, Nevada Power's 3rd Amendment to the 2016-2035 IRP. This update is described in the Load Forecast and Market Fundamentals volume, as well as Technical Appendices LF-1 through LF-7.

Market Fundamentals. The Companies' market fundamentals analysis and price forecasts have been updated from the previously approved forecasts in Docket No. 16-07001, Sierra's 2017-2036 Triennial IRP in Docket No. 16-08027, and Nevada Power's 2nd Amendment to the 2016-2035 IRP. Further details regarding market fundamentals and the fuel and purchased power forecasts can be found in the Load Forecast and Market Fundamentals volume, as well as Technical Appendix FPP-1.

Existing Generation Operating Characteristics and Fixed Costs. Another important input to PROMOD is a complete catalogue of the operating characteristics for each existing generator. This information allows PROMOD to determine the most economic unit commitment and dispatch of the Companies' generation resources. Unit characteristics include maximum and minimum capacities, heat rate curves, fixed and variable O&M, start costs, minimum up and down times, and forced outage rates. Operating characteristics assumptions, including fixed O&M, of the Companies' generation fleet are shown in confidential Technical Appendix Item GEN-1.

New Generation Operating Characteristics and Fixed Costs. Consistent with the Commission's Order in Docket No. 16-07001, the Companies' have not included any new near-term generating resources in the analysis. Future conventional generation build options (also referred to as "conventional placeholders") are assumed as replacements for generating units expected to retire after 2028. The Companies are not requesting approval to build any placeholder resources, and placeholder resources are subject to change in future filings. Additional information about the performance characteristics for conventional build options can be found in Technical Appendix Item GEN-2.

Operating Reserves. As a single Balancing Authority Area ("BAA"), the Companies are a member of the Northwest Power Pool Reserve Sharing Group and must plan to recover from a supply contingency in the form of operating reserves. The Companies' operating reserve requirements comply with Western Electricity Coordinating Council ("WECC") and North American Electric Reliability Corporation ("NERC") standards. Operating reserves include a contingency reserve requirement, a portion of which is spinning reserve (spare online capacity), and a regulating reserve requirement. The operating reserves modeled in PROMOD only considers retail loads - other BAA loads are not included.

The contingency reserve is equal to 6 percent of the combined system load. Spinning reserve requirements are such that at least 50 percent of the contingency reserve must be met with spare capacity from operating (spinning) resources. The regulating reserve requirement is an additional reserve requirement to ensure there is enough spare online capacity available to meet changes in load. The operating reserve calculation is presented in Technical Appendix Item ECON-9.

Renewable Energy. Energy and pricing for existing renewable energy PPAs are modeled in accordance with the terms of the approved PPAs and are consistent between all cases. Future renewable resource additions (also referred to as "renewable placeholders") are added to each case to ensure, at a minimum, compliance with the requirements of Nevada's RPS. The Companies are not requesting approval to acquire or build any renewable placeholder resources, and placeholder resources are subject to change in future filings

As a modeling convenience, placeholder renewables are assumed to be either solar PV systems or geothermal generators. The Companies are not suggesting these renewable resources types are the only renewable resources that will be considered to fulfill future needs. The limitation has been made to minimize differences between cases for yet-to-be-determined renewable resources. A complete listing of the load shapes and pricing for existing renewable energy PPAs and renewable placeholders is provided in Technical Appendix Items REN-1 through REN-2. In all cases, it is assumed that future renewable placeholders contribute toward meeting the requirements of the RPS.

Purchase Power Agreements. Energy and pricing for existing conventional PPAs are modeled in accordance with the terms of the contract and can be found in the Tables marked CON-1 and CON-2 in the discussion of purchased power arrangements above. Future conventional PPA placeholder additions (including "Tolling" agreements) are added as needed to ensure the reliability of each case. As with other placeholders, the Companies are not requesting approval to acquire placeholder resources, and placeholder resources are subject to change in future filings.

Transmission Limits. Transmission limits, including access to external markets as well as limits over ON Line were modeled in accordance with Technical Appendix Item ECON-10. Although PROMOD is not a transmission flow model, all transmission capacity constraints are included in the model and any projected flows based on economics are not allowed to exceed these capacities.

It is important to recognize that all of the plans analyzed by the Companies require the use of transmission capacity to serve load. The Companies utilize transmission capacity pursuant to the Open Access Transmission Tariff ("OATT"), which provides open, non-discriminatory access to the Companies' transmission system for all transmission customers. As the Companies' open position grows, and without the addition of generation within the system, the Companies' become more dependent upon external wholesale generation markets and transmission imports to serve load. In light of current reservations, sufficient transfer capacity exists to cover the imports necessary to meet the open position modeled in each of the primary cases. However, available transmission capacity is dynamic and changes based operational conditions within the transmission system. Additions of load not included in the forecast, generation retirements or outages, and new transmission service requests can create congestion that limits import capacity. Moreover, operational conditions and other changes can further limit the ability to deliver imported supply to areas within the transmission system.

Under the OATT, transmission rights are allocated to the load served by NV Energy only when an external resource can be designated as a network resource (a "Designated Network Resource"). The energy supply strategies embodied in the ESP and each of the primary cases entail a level of risk; namely, the risk that available transmission capacity will be insufficient to allow the Companies to import energy that is either need to serve load or in an economically efficient manner. As system conditions change and as forecast uncertainties come into focus, the Companies may need to modify supply plans or make transmission investments.

Negative Load. To model an hourly output profile, the Companies model renewable resources as load-modifying transactions. That is, the projected hourly output from any renewable resource is subtracted from the expected hourly load. In some hours (e.g., in low load in shoulder or off-seasons), the non-dispatchable output from renewable resources exceeds the forecasted load. This results in a negative number which will cause PROMOD to stop processing. To avoid negative load conditions and to quantify excess energy volumes, the Companies have modeled a zero-cost

firm sale and an off-setting zero-cost generator in PROMOD. The zero-cost sale is interpreted by PROMOD as in increase in the load, and ensures that negative loads are not calculated. The zero-cost generator serves the zero-cost sale *unless* the sale is being served by the excess renewable energy. The difference between the sales energy and the generator energy is the excess renewable energy. This excess is quantified as *dump energy* in the PROMOD output.

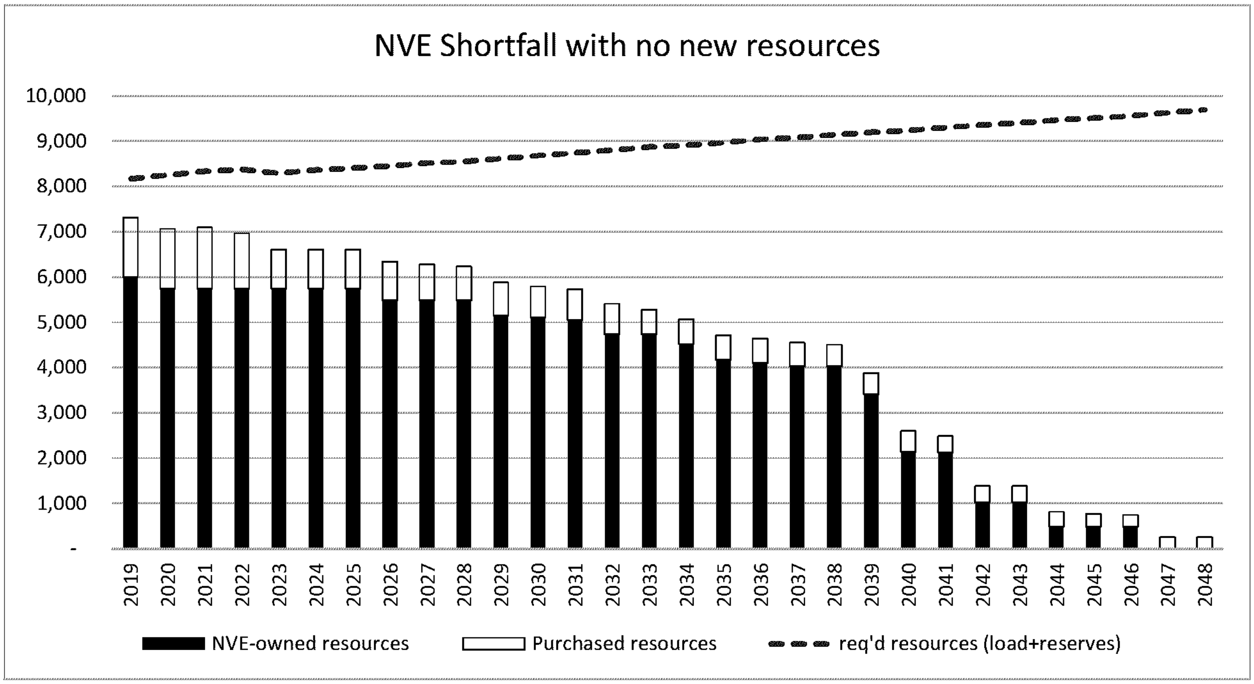
CER Inputs. The CER captures the capital costs of utility-owned resources, such as future generators or transmission infrastructure to be constructed and owned by the Companies. The timing of the project, cash flows during the construction period, AFUDC, and project book lives and tax lives are all factors into the final annual revenue requirement that is captured in the PWRR calculation. Work papers associated with capital projects can be found in Technical Appendix Item ECON-7.

D. PLAN DEVELOPMENT

NAC § 704.937(1) requires a supply plan to contain a "diverse set of alternative plans, which include a list of options for the supply of capacity and electric energy" and that the supply plan "includes a description of all existing and planned facilities for generation and transmission, existing and planned power purchases, and other resources available as options to the utility for the future supply of electric energy." The description must include the expected capacity of the facilities and resources for each year of the supply plan. At least one plan must be of low carbon intensity.

The start to developing expansion plans (or "cases") is to take measure of the Companies' capacity resources and expected requirements. Figure EA-3 below shows the capacity position under Base Load conditions with no new resources added.

FIGURE EA-3
CAPACITY SHORTFALL, BASE LOAD, NO NEW RESOURCES



The capacity requirement assumes the Companies must control approximately 113 percent of their expected load requirement. The 13 percent planning reserve margin is calculated by summing the requirements from Nevada Power's 12 percent planning reserve margin and Sierra's 15 percent planning reserve margin divided by the system peak load. As illustrated in the figure above, the Companies fall short of their required capacity needs in each year of the planning period.

The capacity Open Position between 2019 and 2021 ranges from 607 MW to 1,380 MW. As described in the ESP narrative, the Companies have implemented a 24-month, or four natural gas season ahead, laddering strategy to close the Open Positions with wholesale market purchases ahead of the respective summer season. Based on currently known transmission commitments, the Companies believe there will be sufficient transmission capabilities and market availability to reliability fill the Open Positions through then end of 2021. Moreover, the Renewable Energy Section of the Supply Side narrative shows that Sierra must add renewable resources by in 2022 to remain in compliance with its RPS requirements. In January 2018, the Companies issued the 2018 Renewable RFP, which is detailed in Section 2 of the Supply Side narrative. The need in the same time period for additional renewable energy to meet the RPS as well as for energy and capacity form the basis of the plans developed for this analysis.

Using the results from the 2018 Renewable RFP, the Companies' developed the following four long-term expansion plans:

All Market Case: This case satisfies Sierra's 2022 RPS compliance need with two northern Nevada renewable PPAs: NextEra - Dodge Flat Solar, a 200 MW solar PV facility, and the Cypress Creek - Battle Mountain Solar, 101 MW solar PV facility. Energy and capacity requirements above those provided in these contracts are assumed to be available from the wholesale market.

Renewable Case: This case adds 1,001 MW of solar PV resource through six renewable PPAs, satisfying Sierra's RPS compliance obligation adding low-cost renewable power and 100 MW of co-located battery storage to meet both Companies' supply needs.

- Sierra contracts
  1. NextEra – Dodge Flat Solar (200 MW) with battery energy storage (50 MW/200 MWh)
  2. NextEra – Fish Springs Ranch (100 MW) with battery energy storage (25 MW/100 MWh)
  3. Cypress Creek – Battle Mountain Solar (101 MW) with battery energy storage (25 MW/100 MWh)
- Nevada Power contracts
  4. 8minutenergy – Eagle Shadow Mountain Solar Farm (300 MW)
  5. Sempra – Copper Mountain 5 (250 MW)
  6. 174 Power Global – Techren V (50 MW)

Low Carbon Case: This variation of the Renewable Case includes the conditional retirement of North Valmy Unit 1 on December 31, 2021.

- Sierra contracts
  1. NextEra – Dodge Flat Solar (200 MW) with battery energy storage (50 MW/200 MWh)
  2. NextEra – Fish Springs Ranch (100 MW) with battery energy storage (25 MW/100 MWh)
  3. Cypress Creek – Battle Mountain Solar (101 MW) with battery energy storage (25 MW/100 MWh)
- Nevada Power contracts
  4. 8minutenergy – Eagle Shadow Mountain Solar Farm (300 MW)
  5. Sempra – Copper Mountain 5 (250 MW)
  6. 174 Power Global – Techren V (50 MW)

Development Case: This is a variation of the Low Carbon Case, which includes the conditional retirement of North Valmy Unit 1 as well as two additional Company-developed solar PV facilities.

- Sierra contracts
  1. NextEra – Dodge Flat Solar (200 MW) with battery energy storage (50 MW/200 MWh)

2. NextEra – Fish Springs Ranch (100 MW) with battery energy storage (25 MW/100 MWh)
3. Cypress Creek – Battle Mountain Solar (101 MW) with battery energy storage (25 MW/100 MWh)

- Nevada Power contracts
  4. 8minutenergy – Eagle Shadow Mountain Solar Farm (300 MW)
  5. Sempra – Copper Mountain 5 (250 MW)
  6. 174 Power Global – Techren V (50 MW)
- NV Energy developed solar PV facilities
  7. Dry Lake Solar (150 MW)
  8. Crescent Valley Solar (149 MW)

Renewable Placeholders (Beyond the Action Plan Period). Future renewable placeholders were added outside the Action Plan period where necessary to ensure that each plan meets or exceeds compliance with Nevada's RPS through the planning period. These renewables also help to fill Open Positions through the planning period. The renewable placeholders are a function of the Companies' projected sales. The size and timing of geothermal placeholders were held constant in each load sensitivity. However, solar PV placeholders changed from one plan to another to account for the differences in PPAs across the resource plans.

Figures EA-4 through EA-7 show the renewable resource additions for each plan for Base, High, Low, and 704B load scenarios, respectively.

FIGURE EA-4
BASE LOAD - RENEWABLE RESOURCE PLACEHOLDERS

Nevada Power Renewable Placeholders by Case - BASE load	
All Market	Renewable, Low Carbon and Development Cases
	100 MW PV -2023
	50 MW PV -2023
100 MW PV -2027	
75 MW PV -2027	
100 MW PV -2028	
75 MW PV -2028	
100 MW PV -2030	100 MW PV -2030
100 MW PV -2030	100 MW PV -2030
50 MW PV -2030	50 MW PV -2030
25 MW PV -2031	100 MW PV -2031
	100 MW PV -2031
25 MW PV -2032	100 MW PV -2032
	100 MW PV -2032
	50 MW PV -2032
100 MW PV -2033	100 MW PV -2033
100 MW PV -2033	100 MW PV -2033
100 MW PV -2033	100 MW PV -2033
100 MW PV -2033	
75 MW PV -2033	
50 MW Geo-2035	50 MW Geo-2035
100 MW PV -2041	
100 MW PV -2041	
25 MW PV -2041	
50 MW PV -2042	
25 MW PV -2043	100 MW PV -2044
100 MW PV -2044	
25 MW PV -2046	
25 MW PV -2047	100 MW PV -2048
	100 MW PV -2048

Sierra Renewable Placeholders by Case - BASE load	
All Market	Renewable, Low Carbon and Development Cases
	100 MW PV -2022
25 MW PV -2023	50 MW PV -2023
75 MW PV -2025	
100 MW PV -2026	
75 MW PV -2027	
25 MW PV -2028	
50 MW PV -2029	50 MW PV -2029
25 MW PV -2031	25 MW PV -2031
50 MW PV -2038	75 MW PV -2038
	50 MW PV -2039
25 MW PV -2040	
	50 MW PV -2042
50 MW PV -2046	
50 MW Geo-2047	50 MW Geo-2047
100 MW PV -2047	100 MW PV -2047
25 MW PV -2047	100 MW PV -2047
	100 MW PV -2047
50 MW PV -2048	100 MW PV -2048

FIGURE EA-5
HIGH LOAD - RENEWABLE RESOURCE PLACEHOLDERS

Nevada Power Renewable Placeholders by Case - HIGH load	
All Market	Renewable, Low Carbon and Development Cases
50 MW PV - 2021	
	100 MW PV - 2023
	50 MW PV - 2023
100 MW PV - 2027	
75 MW PV - 2027	
100 MW PV - 2028	
75 MW PV - 2028	
25 MW PV - 2029	
100 MW PV - 2030	100 MW PV - 2030
100 MW PV - 2030	100 MW PV - 2030
75 MW PV - 2030	50 MW PV - 2030
	100 MW PV - 2031
	100 MW PV - 2031
50 MW PV - 2032	100 MW PV - 2032
	100 MW PV - 2032
	50 MW PV - 2032
100 MW PV -2033	100 MW PV - 2033
100 MW PV -2033	100 MW PV - 2033
100 MW PV -2033	100 MW PV - 2033
100 MW PV -2033	
75 MW PV -2033	
50 MW Geo - 2035	50 MW Geo - 2035
75 MW PV - 2040	
100 MW PV - 2041	
100 MW PV - 2041	
50 MW PV - 2041	
25 MW PV - 2042	
100 MW PV - 2044	100 MW PV - 2044
25 MW PV - 2045	
100 MW PV - 2046	
25 MW PV - 2048	100 MW PV - 2048
	100 MW PV - 2048

Sierra Renewable Placeholders by Case - HIGH load	
All Market	Renewable, Low Carbon and Development Cases
75 MW PV - 2021	
	100 MW PV - 2022
50 MW PV -2023	50 MW PV - 2023
100 MW PV - 2025	
25 MW PV - 2025	
100 MW PV - 2026	
50 MW PV - 2027	
25 MW PV - 2028	100 MW PV - 2028
	25 MW PV - 2028
75 MW PV - 2029	100 MW PV - 2029
	50 MW PV - 2029
	50 MW PV - 2030
25 MW PV - 2031	
75 MW PV - 2038	
	50 MW PV - 2041
25 MW PV - 2042	25 MW PV - 2042
25 MW PV - 2045	
75 MW PV - 2046	75 MW PV - 2046
50 MW Geo- 2047	50 MW Geo- 2047
100 MW PV - 2047	100 MW PV - 2047
75 MW PV - 2047	100 MW PV - 2047
	75 MW PV - 2047
50 MW PV - 2048	75 MW PV - 2048

FIGURE EA-6
LOW LOAD - RENEWABLE RESOURCE PLACEHOLDERS

Nevada Power Renewable Placeholders by Case - LOW load	
All Market	Renewable, Low Carbon and Development Cases
	100 MW PV - 2023
	50 MW PV - 2023
100 MW PV - 2028	
75 MW PV - 2028	
100 MW PV - 2029	
25 MW PV - 2029	
100 MW PV - 2030	
100 MW PV - 2030	
50 MW PV - 2030	
100 MW PV -2033	
100 MW PV -2033	
100 MW PV -2033	
100 MW PV -2033	
75 MW PV -2033	
50 MW Geo - 2035	50 MW Geo - 2035
50 MW PV - 2041	100 MW PV -2041
100 MW PV - 2042	
100 MW PV - 2042	
50 MW PV - 2044	100 MW PV -2044
25 MW PV - 2045	
50 MW PV - 2046	100 MW PV - 2046
	100 MW PV - 2046
	100 MW PV - 2046
	100 MW PV - 2046
	100 MW PV - 2046
	50 MW PV - 2046
	100 MW PV - 2047
	100 MW PV - 2047
	100 MW PV - 2047

Sierra Renewable Placeholders by Case - LOW load	
All Market	Renewable, Low Carbon and Development Cases
	100 MW PV - 2022
	50 MW PV - 2023
100 MW PV - 2027	
50 MW PV -2027	
75 MW PV - 2028	
50 MW PV - 2029	
25 MW PV - 2031	
25 MW PV - 2039	
25 MW PV - 2041	
25 MW PV - 2044	50 MW PV - 2044
	75 MW PV - 2045
	50 MW PV - 2046
50 MW Geo- 2047	50 MW Geo- 2047
100 MW PV - 2047	100 MW PV - 2047
50 MW Geo- 2047	100 MW PV - 2047
	100 MW PV - 2047
	50 MW PV - 2048

FIGURE EA-7
704B LOAD - RENEWABLE RESOURCE PLACEHOLDERS

Nevada Power Renewable Placeholders by Case - 704B load	
All Market	Renewable, Low Carbon and Development Cases
	100 MW PV - 2023
	50 MW PV - 2023
50 MW PV - 2028	
100 MW PV - 2029	
100 MW PV - 2029	
50 MW PV - 2029	
100 MW PV - 2030	
100 MW PV - 2030	
50 MW PV - 2030	
25 MW PV - 2031	
25 MW PV - 2032	
100 MW PV -2033	100 MW PV -2033
100 MW PV -2033	100 MW PV -2033
100 MW PV -2033	
100 MW PV -2033	
50 MW PV -2033	
50 MW Geo - 2035	50 MW Geo - 2035
	100 MW PV -2037
75 MW PV - 2040	
100 MW PV - 2041	
100 MW PV - 2041	
25 MW PV - 2041	
25 MW PV - 2043	
100 MW PV - 2044	
	100 MW PV -2045
25 MW PV - 2046	100 MW PV - 2047
	100 MW PV - 2047
	100 MW PV - 2047
	100 MW PV - 2047
	100 MW PV - 2047
25 MW PV - 2048	100 MW Geo- 2048
	100 MW PV - 2048
	100 MW PV - 2048
	100 MW PV - 2048
	100 MW PV - 2048

Sierra Renewable Placeholders by Case - 704B load	
All Market	Renewable, Low Carbon and Development Cases
	100 MW PV -2022
25 MW PV -2023	50 MW PV -2023
75 MW PV -2025	
100 MW PV -2026	
75 MW PV -2027	
25 MW PV -2028	
50 MW PV -2029	50 MW PV -2029
25 MW PV -2031	25 MW PV -2031
50 MW PV -2038	75 MW PV -2038
	50 MW PV -2039
25 MW PV -2040	
	50 MW PV -2042
50 MW PV -2046	
50 MW Geo-2047	50 MW Geo-2047
100 MW PV -2047	100 MW PV -2047
25 MW PV -2047	100 MW PV -2047
	100 MW PV -2047
50 MW PV -2048	100 MW PV -2048

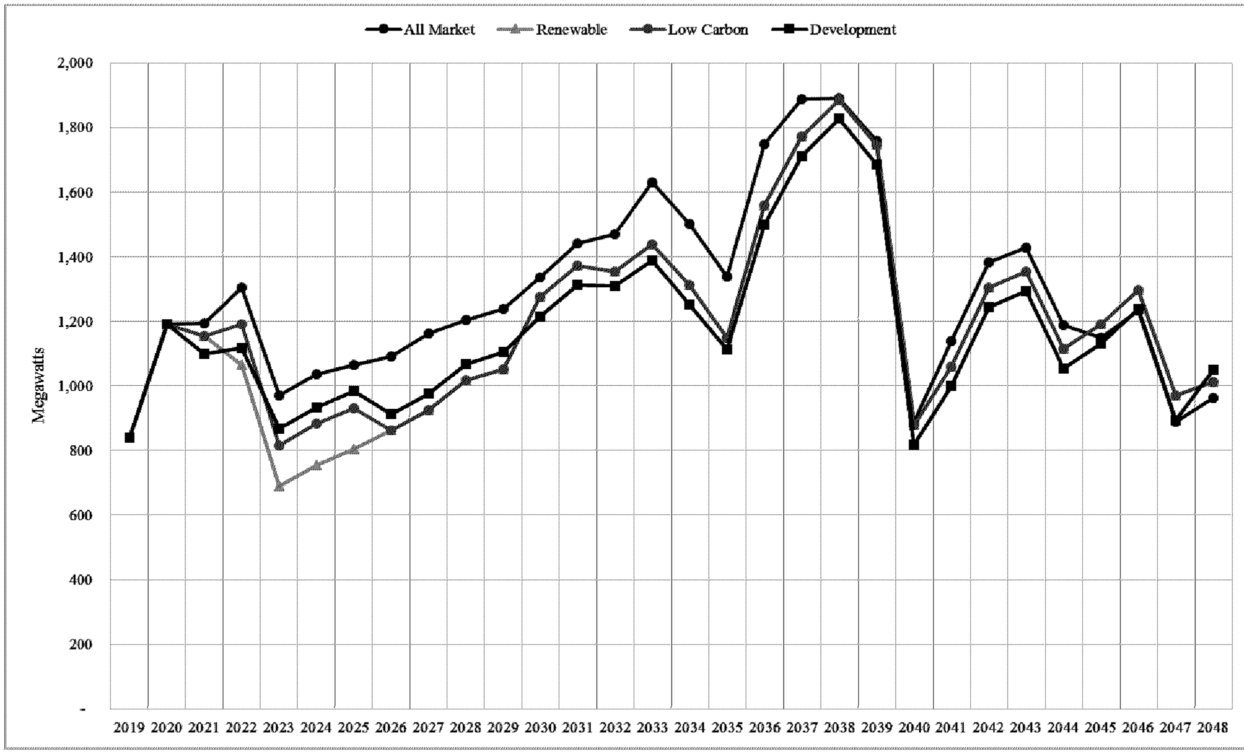
Conventional Placeholders (Beyond the Action Plan Period). Future conventional placeholders have been added to each plan only as replacements for existing conventional generators. This 2018 Joint IRP does not include any NV Energy developed natural gas-fired resources until 2029, following the 2028 retirements of Tracy Station Unit 3, and Fort Churchill Units 1 and 2. Conventional placeholders were held constant for all cases and scenarios and are listed in Figure EA-8.

FIGURE EA-8
CONVENTIONAL RESOURCE PLACEHOLDERS

Conventional Placeholder Units in All Plans for every scenario				
Placeholder Unit	Year	Number	Unit	Single Unit Output at System Peak
1-1x1 CC NN 358 MW_29	2029	1	1x1 Combined-Cycle	358 MW
1-1x1 CC NN 358 MW_32	2032	1	1x1 Combined-Cycle	358 MW
1-1x1 CC SN 382 MW_34	2034	1	1x1 Combined-Cycle	382 MW
1-1x1 CC SN 382 MW_35	2034	1	1x1 Combined-Cycle	382 MW
2-CT NN 84 MW_35	2035	2	Combution Turbine	84 MW
9-CT SN 90 MW_39	2039	9	Combution Turbine	90 MW
1-1x1 CC SN 382 MW_40	2040	1	1x1 Combined-Cycle	382 MW
2-2x1 CC SN 900 MW_40	2040	2	2x1 Combined-Cycle	900 MW
1-2x1 CC SN 900 MW_42	2042	1	2x1 Combined-Cycle	900 MW
1-2x1 CC NN 839 MW_44	2044	1	2x1 Combined-Cycle	358 MW
1-2x1 CC SN 900 MW_47	2047	1	2x1 Combined-Cycle	900 MW

Open Positions and Open Position Capacity Costs. Figure EA-9 shows the Open Positions of each plan under the Base Load sensitivity. As explained in the Load Forecast and Market Fundamentals volume, the purchase power price forecast includes a monthly capacity charge associated with firm capacity purchases. This capacity charge is reflected in the pricing in each plan and is a function of the size of the Open Positions for each case. As has been described, each of the plans has a slightly different Open Position but attempts are made to make the resource additions being evaluated in each case approximately the same size so that the reliability of each case, dependence on the market for capacity and energy, and the capacity cost of each case are similar.

FIGURE EA-9
OPEN POSITION FOR EACH RESOURCE PLAN CASE



Low Carbon Intensity Plan. NAC §§ 704.9355(1)(e) and 704.937(1), which implement legislative changes to NRS § 704.741, provide that a utility must include in its supply plan at least one alternative plan of "low carbon intensity." A low carbon intensity plan is defined as:

- The generation or acquisition of an amount of renewable energy greater than required by the RPS;
- Changes to the utility's existing fleet of resources for the generation of power;
- The application of technology that would significantly reduce emissions of carbon; or
- Any combination thereof.

The Companies have constructed the Low Carbon case to comply with NRS § 704.741, and NAC §§ 704.9355(1)(e) 704.937(1). In addition to exceeding the RPS, the Low Carbon Case includes the addition of battery energy storage systems, and the conditional retirement of North Valmy Unit 1.

Long-Term Transmission Rights. NAC § 704.9355(1)(c)(f) provides that a resource plan should include an analysis that considers the availability of long-term transmission rights and wholesale power purchases for delivery to the Companies' BAA. All alternative plans include some level of market purchases as a resource option. Market purchases are assumed to be at the border of the Companies' BAA. The resource additions in the Preferred and Alternate plans do not require the

addition of long-term transmission rights on third-party transmission assets, since all of the resource additions are located within the Companies' BAA in Nevada.

E. ECONOMIC ANALYSIS RESULTS

The results of the economic analysis follows and begins with Figures EA-10 and EA-11 which contain the PWRRs for all load, fuel and purchase power price, and carbon sensitivities over 20 and 30 years respectively. A discussion of the key findings from the results follows the figures.

FIGURE EA-10
20-YEAR PWRRs FOR ALL CASES AND SENSITIVITIES

2018 IRP 20-year PWRR ($ millions) by Scenario									
	Base Load						DOS Load	High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	DOSBFMC	HLBFMC	LLBFMC
All Market	$ 17,714	$ 17,175	$ 18,173	$ 17,441	$ 21,596	$ 15,201	$ 17,395	$ 19,135	$ 16,761
Renewable	$ 17,579	$ 17,097	$ 17,984	$ 17,333	$ 21,264	$ 15,196	$ 17,251	$ 18,994	$ 16,655
Low Carbon	$ 17,601	$ 17,119	$ 18,006	$ 17,355	$ 21,286	$ 15,218	$ 17,273	$ 19,016	$ 16,675
Development	$ 17,654	$ 17,195	$ 18,042	$ 17,420	$ 21,270	$ 15,318	$ 17,328	$ 19,043	$ 16,716

2018 IRP 20-year PWRR Differential ($ millions) by Scenario									
	Base Load						DOS Load	High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	DOSBFMC	HLBFMC	LLBFMC
All Market	$ 135	$ 78	$ 188	$ 107	$ 332	$ 5	$ 143	$ 141	$ 106
Renewable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Low Carbon	$ 22	$ 22	$ 22	$ 22	$ 22	$ 22	$ 22	$ 21	$ 20
Development	$ 75	$ 98	$ 57	$ 87	$ 6	$ 122	$ 77	$ 49	$ 61

2018 IRP 20-year PWRR Ranking by Scenario									
	Base Load						DOS Load	High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	DOSBFMC	HLBFMC	LLBFMC
All Market	4	3	4	4	4	2	4	4	4
Renewable	1	1	1	1	1	1	1	1	1
Low Carbon	2	2	2	2	3	3	2	2	2
Development	3	4	3	3	2	4	3	3	3

FIGURE EA-11
30-YEAR PWRRs FOR ALL CASES AND SENSITIVITIES

2018 IRP 30-year PWRR ($ millions) by Scenario									
	Base Load						DOS Load	High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	DOSBFMC	HLBFMC	LLBFMC
All Market	$ 23,659	$ 22,357	$ 24,787	$ 23,018	$ 30,072	$ 19,836	$ 23,248	$ 25,876	$ 22,096
Renewable	$ 23,482	$ 22,240	$ 24,545	$ 22,873	$ 29,662	$ 19,796	$ 23,083	$ 25,686	$ 22,000
Low Carbon	$ 23,504	$ 22,262	$ 24,567	$ 22,895	$ 29,685	$ 19,817	$ 23,105	$ 25,708	$ 22,021
Development	$ 23,533	$ 22,328	$ 24,571	$ 22,939	$ 29,608	$ 19,917	$ 23,117	$ 25,694	$ 22,008

2018 IRP 30-year PWRR Differential ($ millions) by Scenario									
	Base Load						DOS Load	High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	DOSBFMC	HLBFMC	LLBFMC
All Market	$ 177	$ 116	$ 242	$ 145	$ 464	$ 41	$ 165	$ 190	$ 96
Renewable	$ -	$ -	$ -	$ -	$ 55	$ -	$ -	$ -	$ -
Low Carbon	$ 22	$ 22	$ 22	$ 22	$ 77	$ 22	$ 22	$ 21	$ 20
Development	$ 51	$ 88	$ 26	$ 66	$ -	$ 121	$ 34	$ 8	$ 8

2018 IRP 30-year PWRR Ranking by Scenario									
	Base Load						DOS Load	High Load	Low Load
	BLBFMC	BLBFNC	BLBFHC	BLBFLC	BLHFMC	BLLFMC	DOSBFMC	HLBFMC	LLBFMC
All Market	4	4	4	4	4	3	4	4	4
Renewable	1	1	1	1	2	1	1	1	1
Low Carbon	2	2	2	2	3	2	2	3	3
Development	3	3	3	3	1	4	3	2	2

The key findings of the 20-year and 30-year PWRR analysis are summarized below.

- The Renewable Case consistently produced the lowest PWRR in all but the high fuel sensitivity. The PWRR differences between the Renewable Case and the Low Carbon Case are in the four year period from 2022 through 2025, and are largely attributable to the Open Position costs associated with the retirement of North Valmy Unit 1.
- In most scenarios, the All Market case underperforms against the Renewable, Low Carbon, and the Development cases. This is due in large part to the growing Open Position and reliance on third party energy and capacity in the wholesale power market.
- The addition of low cost solar PV PPAs in the Renewable, Low Carbon, and Development cases diversifies the energy mix of Nevada and reduces reliance on out of state energy supply, namely natural gas and wholesale purchase power.

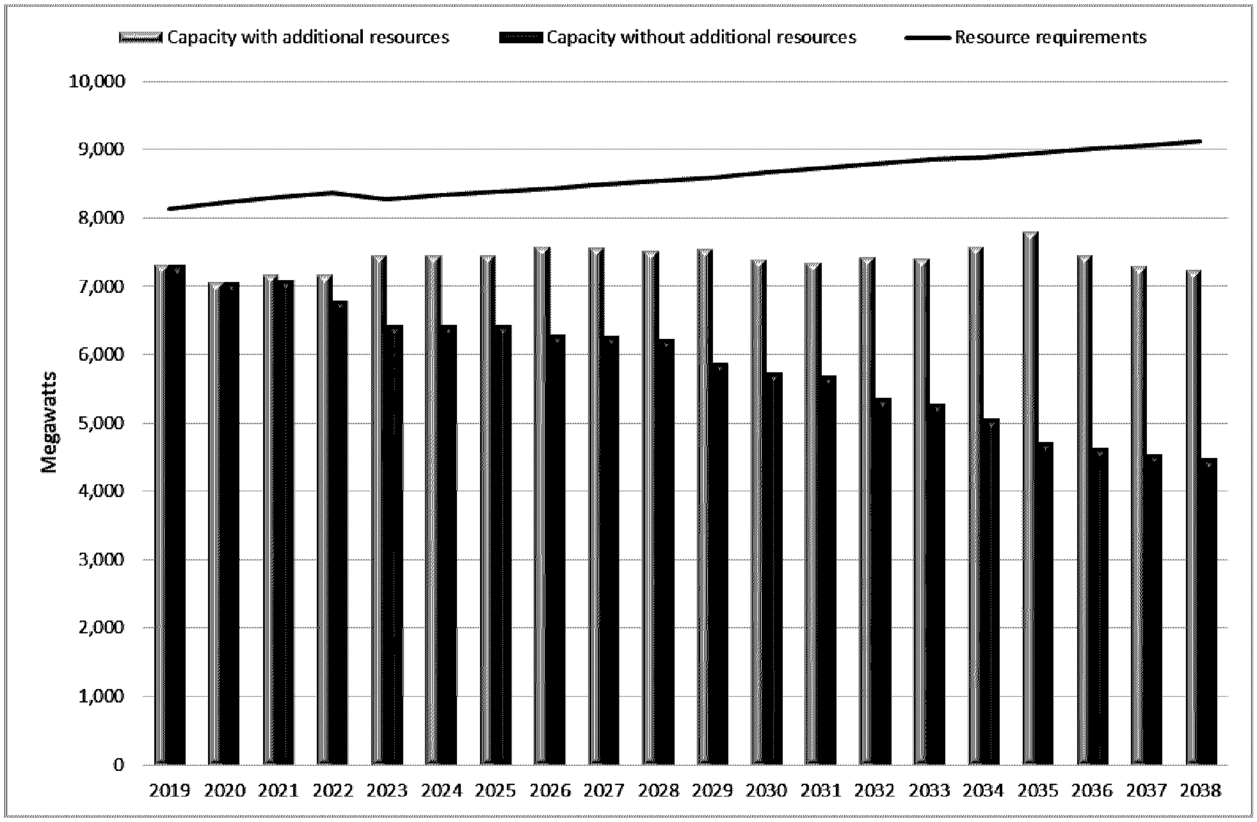
F. SELECTION OF THE PREFERRED AND ALTERNATIVE PLANS

NAC § 704.948 requires that "a utility shall analyze its decisions, taking into account its assessment of risk and identifying particular risks with respect to: (a) costs, (b) reliability, (c) finances, (d) the volatility of the price of purchased power and fuel, and (e) any other uncertainties the utility has identified."

The Companies selected the Low Carbon Case as their Preferred Plan and the similar Renewable Case as the Alternative Plan. The Renewable Case has the lowest PWRR. With respect to the impact on the State's economy, both cases involve an estimated $2.175 billion progressive investment in Nevada, provide an estimated 1,785 construction jobs and approximately 76 long-term jobs. Turning to the impact on the environment, the Low Carbon Case minimizes the impact of the Companies' operations on the State, national and global environment. The Companies selected the Low Carbon Case based the fact that with the earlier retirement of North Valmy Unit 1, the case is more closely aligned with Nevada's energy policy and delivers the services our customers value.

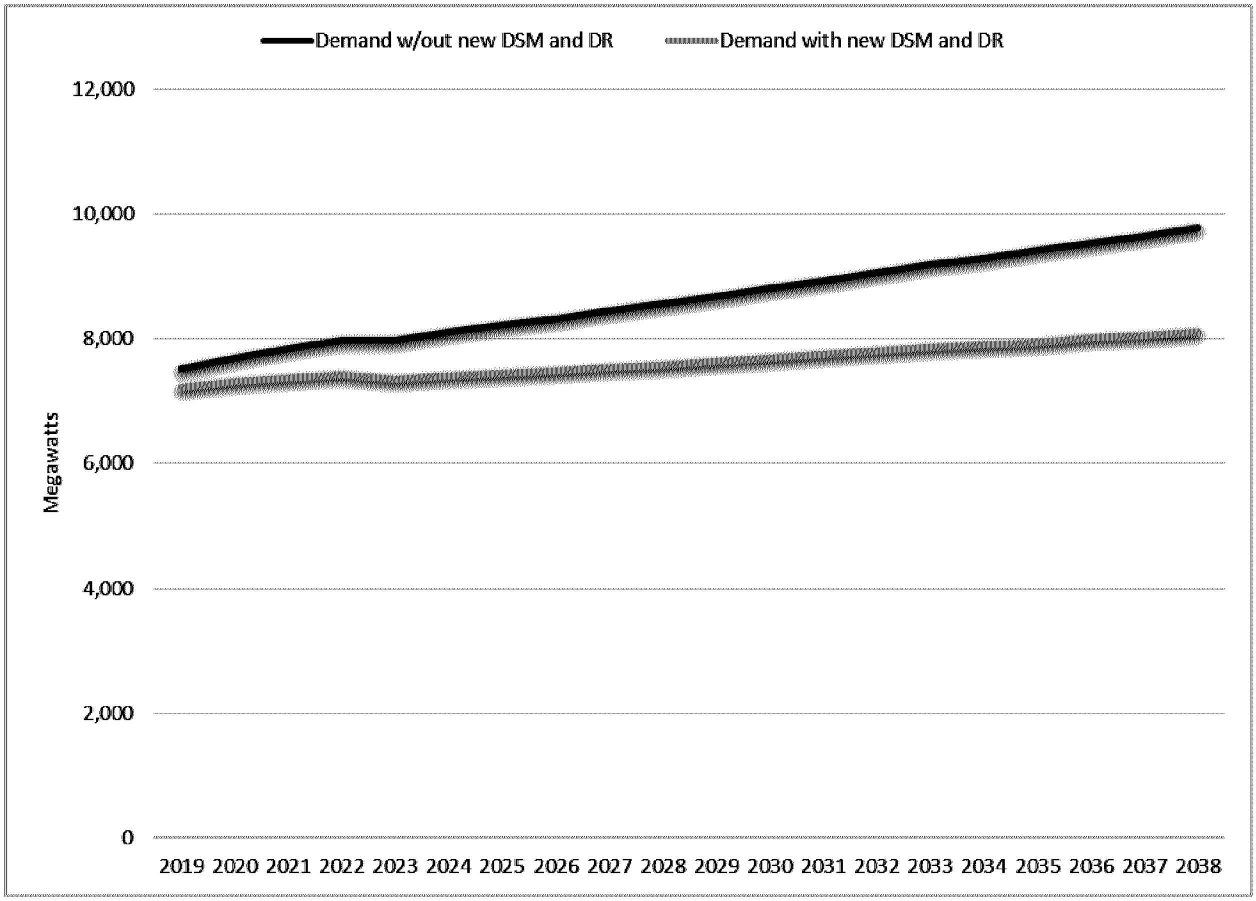
Preferred Plan Graphs. NAC §§ 704.945(2) and (3) require that the Companies include certain graphs illustrating the features of the Preferred Plan. Figure EA-12 below compares the total resource requirements to the total capacity with and without additional planned resources.

FIGURE EA-12
RESOURCE REQUIREMENTS, CAPACITY WITH ADDITIONAL RESOURCES, CAPACITY WITHOUT ADDITIONAL RESOURCES



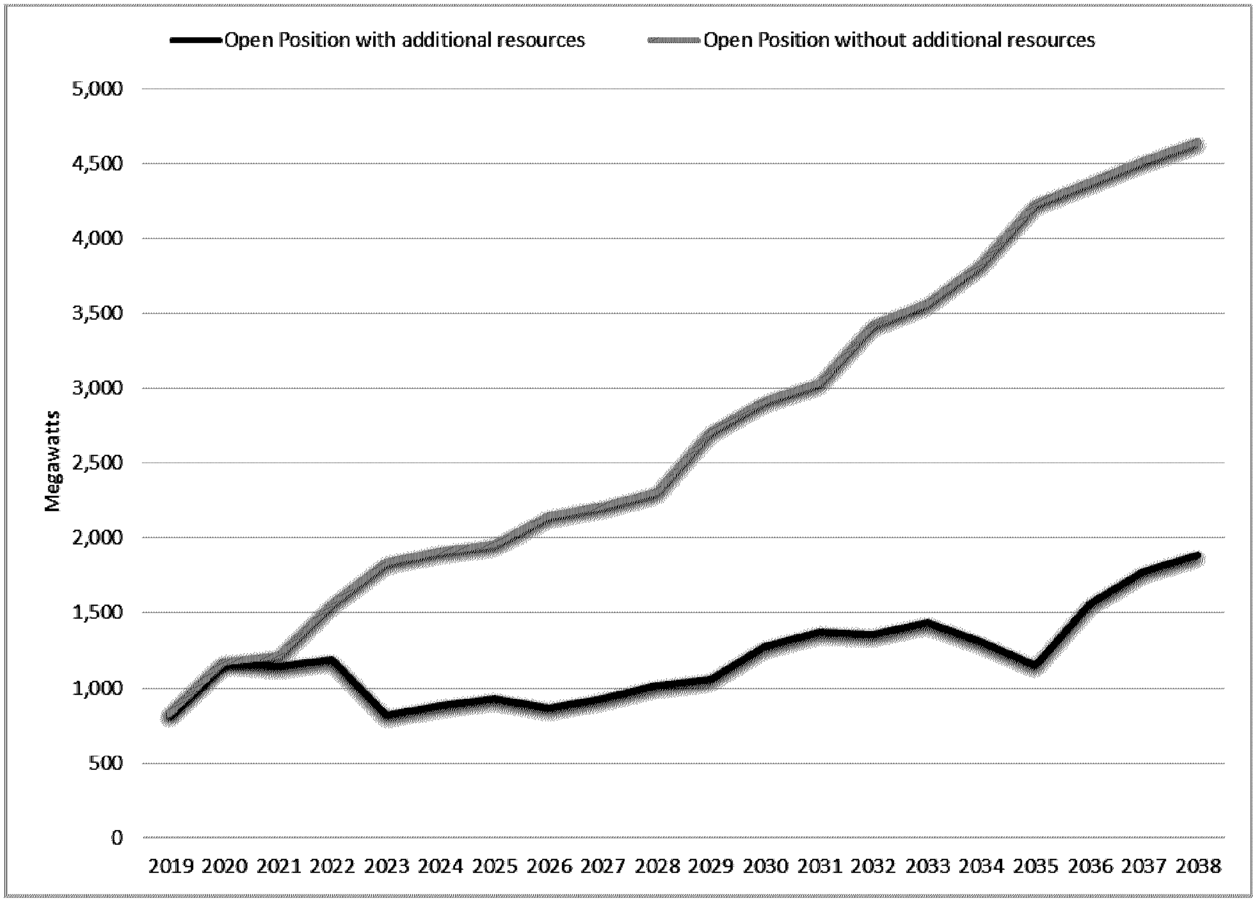
The effect of new programs for energy efficiency and conservation on peak demand are depicted in Figure EA-13.

FIGURE EA-13
DEMAND WITH AND WITHOUT NEW ENERGY EFFICIENCY AND CONSERVATION PROGRAMS



Under the Preferred Plan, the Companies continue to have an Open Position for the duration of the resource plan period. However, the magnitude of the Open Position is significantly mitigated with the addition of the Preferred Plan resources when compared to the scenario where no additional resources are added. A comparison of the required capacity with and without the additional planned resources is shown in Figure EA-14.

FIGURE EA-14
REQUIRED CAPACITY WITH AND WITHOUT ADDITIONAL RESOURCES



All of the cases analyzed assume that Question 3 is not approved by voters in November 2018. Consequently, these plans allow long-term commitments to supply side resources to be made for the benefit of customers.

As noted in the introduction, this 2018 Joint IRP is filed at a pivotal point: Nevadans will decide in November whether the state constitution should be amended and the existing resource planning and energy production and delivery system should be dismantled. If Question 3 passes in November, NV Energy will sell its generation resources, assign long-term energy supply contracts, and cease selling energy to end-use customers. During the transition period, the Companies will be engaged in short-term planning focused on ensuring that energy is safely and reliably delivered to customers through 2023. Consistent with the guidance provided by the Commission in previous integrated resource plan proceedings, long-term commitments for the supply of energy would be minimized.

To address this significant contingency and uncertainty, the Companies identified a single case that meets the needs of customers only through 2023. In that scenario, the lowest cost renewable

energy contract, Nevada Power's PPA with 8minutenergy for the output of a 300 MW facility, would be assigned to Sierra in order to ensure compliance with Nevada's RPS through 2032. The PWRR of that scenario was calculated for the 5-year period. The 5-year PWRR of that case is $5.68 billion. This figure does not take into consideration the present value of costs that would be incurred, as identified by the Commission in its investigative report issued in Docket No. 17-10001. Because the scenario does not result in the reliable delivery of energy beyond the 5-year planning horizon, NV Energy was unable to compute the PWRR for additional planning horizons.

G. LOADS AND RESOURCES TABLES

NAC § 704.945 requires a table of loads and resources for each alternative plan analyzed. For the Preferred Plan, the 30-year projection of peak load, planning reserve requirements, total required resources, existing and future supply-side resources, and existing and future demand-side resources is provided in Figure EA-15. L&R tables for each Company under the alternative plans, including the High Load, Low Load, and 704B Load scenarios, are provided in Technical Appendix Item ECON-6.

Overview. In previous resource plan filings, separate L&R tables were prepared for Sierra and Nevada Power. The L&R tables have been combined for this joint IRP. The L&R tables provide the forecasted peak load (in MW) for the peak hour of the peak day of the year ("Peak Load"), the Peak Load plus a planning reserve requirement ("Required Resources"), and the forecasted capacities of the existing and future supply-side and demand-side resources (in MW) available to meet the Required Resources. The first three years of the plan include an adjustment to Peak Load to account for the differences in the peak hour for each Company.

The Peak Load includes wholesale firm sales and is net of demand-side resources including demand-side management programs, demand response programs, and net metering programs. Loads within the BAA for customers that supply their own supply-side and demand-side resources, such as those authorized to procure their own energy supply under NRS Chapter 704B, are not included in the load that the Companies plans to serve. Additionally, some existing and new customers have asked the Companies not to plan on providing energy supply resources on their behalf, as they may file applications for permission to procure their own energy. As is discussed in the Load Forecast discussion, the potential load for these customers has not been included in the load forecast, and so has not been included in the calculation of resource requirements.

Planning reserve margins of approximately 13 percent are added to the Peak Load to determine the Required Resources. This level of planning reserve is the sum of the planning reserves for Nevada Power and Sierra. Each Company's planning reserve margin was selected to achieve a loss of load probability of no more than 1 day in 10 years. The planning reserve margins in this joint filing ensure that the Companies plan for sufficient supply-side resources and demand-side resources to meet the total requirements of native load customers, including planning reserves.

Supply-side resources include a combination of existing and planned generation and PPAs, both conventional and renewable. The capacity value assigned to supply-side resources represents the expected available capacity of each resource during the Peak Load.

Overall, the L&R tables represent the diverse set of resource options maintained by the Companies to meet the expected Required Resources.

Methodology for Assigning L&R Capacity Values for Existing and Future Resources. The capacity at the time of Peak Load for existing conventional generation is listed in Technical Appendix Item GEN-1. The capacity of future conventional placeholders can be found in Technical Appendix Item GEN-2. The capacity for conventional generators varies depending on the time of the year and is categorized as winter capacity, summer capacity, or peak capacity. The peak capacity value is used for existing conventional generators on the L&R tables. For PPAs for conventional generation, the contractually agreed upon capacity during the Peak Load hour is used.

For existing non-intermittent rewewable energy resources (*e.g.*, geothermal and hydro) the capacity reflected on the L&R tables is based on the peak hour generation commitment in the energy supply table in the applicable PPAs. The standard PPA energy supply table provides average hourly generator forecasts for each month of the year. The value used for the L&R tables is the hour ending 17:00 (5 p.m.) in July. In some cases, historical performance regarding the amount of generation capacity that can be reliably provided during such periods is used to adjust the value in the energy supply table. The capacity that can be counted on during the Peak Load hour is typically lower than the nameplate capacity of the generator. For existing wind resources, the capacity value of the resource as reflected on the L&R table is 10 percent of nameplate capacity. For existing solar PV resources, the capacity value of the resource as reflected on the L&R table is based on the Effective Load Carrying Capability ("ELCC") study conducted by the Companies in compliance with Directive 8 in Docket No. 15-07004. The report is attached as Technical Appendix ECON-11. The L&R value for all (existing and new) solar PV varies inversely with the amount of solar PV penetration on the system. That is, as the total aggregate amount of nameplate solar PV capacity increases, the percent of nameplate capacity decreases. The percentage begins in the most current year as 33 percent of nameplate capacity. As the amount of solar PV penetration on the system increases, the percent of nameplate capacity decreases, the lowest being 20 percent.

For future non-intermittent renewable placeholders, energy supply tables for current PPAs sourced from similar technologies and sizes are used to determine the peak capacity during Peak Load in the L&R tables. In the case of intermittent renewable generation, the same adjustment is made to the future placeholders as is made for existing PPAs for these types of generation. A declining

capacity value of 33 to 20 percent of the nameplate rating is assigned for purposes of preparing the L&R tables for future solar PV.

The L&R tables show existing contracts expiring per the contract expiration date. Renewable placeholder contracts are added as needed to meet requirements for RPS compliance.

Since the L&R tables provide a projection of capacity only, the capacity values cannot be extrapolated to forecast retail energy sales, total megawatt-hour output from conventional and renewable resources, or portfolio credit contributions to meet Nevada's RPS.

Combined L&R Tables. Figure EA-15 provides the L&R table for the Preferred Plan under the Base Load scenario. The L&R table includes the following updates as compared to the tables filed in Sierra's 2016 IRP, Docket No. 16-07001.

- The L&R tables for Nevada Power and Sierra have been combined.
- The resources have been grouped into categories (e.g., NVE existing Gas, NVE existing Renewable, placeholder renewable, placeholder gas, proposed renewable PPAs).
- The L&R table is built from an updated load forecast, which is described in detail in the Load Forecast and Market Fundamentals volume.
- The L&R table incorporates updated demand-side management and demand response plans and net metering assumptions.
- Renewable and conventional placeholders have been optimized.

FIGURE EA-15
L&R TABLE LOW CARBON CASE
(2019-2038)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gross Peak	7,596	7,786	7,955	8,100	8,110	8,251	8,368	8,483	8,617	8,732	8,858	8,985	9,114	9,252	9,380	9,492	9,619	9,754	9,870	10,009
DSM	86	150	214	281	346	411	478	543	611	678	745	813	881	950	1,018	1,087	1,156	1,226	1,296	1,366
Net Metering	68	91	109	125	141	152	155	160	166	172	176	181	185	192	196	200	206	213	216	221
Demand Response	225	242	262	277	280	284	288	290	302	305	307	303	308	311	310	314	314	308	309	319
NET System Peak	7,217	7,303	7,370	7,417	7,343	7,404	7,447	7,490	7,538	7,577	7,630	7,688	7,745	7,799	7,856	7,891	7,943	8,007	8,049	8,103
Planning Reserves (13%)	938	949	958	944	931	939	944	949	955	960	966	973	980	987	994	999	1,005	1,013	1,018	1,025
REQUIRED RESOURCES	8,155	8,252	8,328	8,361	8,274	8,343	8,391	8,439	8,493	8,537	8,596	8,661	8,725	8,786	8,850	8,890	8,948	9,020	9,067	9,128
AVAILABLE RESOURCES	7,315	7,060	7,168	7,170	7,459	7,459	7,459	7,577	7,567	7,520	7,544	7,387	7,353	7,431	7,411	7,578	7,798	7,461	7,294	7,242
OPEN Position	840	1,192	1,160	1,191	815	884	932	862	926	1,017	1,052	1,274	1,372	1,355	1,439	1,312	1,150	1,559	1,773	1,886
Company	(All)																			
Row Labels	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
existing																				
NVE.existing.Coal	516	261	261	134	134	134	134	-	-	-	-	-	-	-	-	-	-	-	-	-
NVE.existing.Gas	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,475	5,141	5,098	5,039	4,725	4,725	4,510	4,163	4,091	4,019	4,019
PPA.existing.Conventional	710	710	710	620	271	271	271	271	271	271	271	271	271	259	259	259	259	259	259	259
NVE.existing.Renewable.PV	5	5	5	4	4	4	4	4	4	4	4	3	3	3	3	3	3	3	3	3
PPA.existing.Renewable.PV	270	270	303	228	228	228	228	228	228	228	228	178	178	178	178	178	174	174	154	94
PPA.existing.Renewable.GEO	173	173	172	168	156	156	156	143	133	118	108	67	67	63	7	7	7	7	7	-
NVE.existing.Renewable.WH	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
PPA.existing.Renewable.LFG	9	9	9	9	9	9	9	9	9	9	9	9	9	9	-	-	-	-	-	-
PPA.existing.Renewable.CSP	128	128	128	128	128	128	128	128	128	100	100	100	100	100	100	100	100	100	100	100
PPA.existing.Renewable.WIND	15	15	15	15	15	15	15	15	15	15	15	15	15	15	-	-	-	-	-	-
PPA.existing.Renewable.HYDRO	9	9	9	9	9	9	9	9	9	5	3	3	3	3	3	3	3	3	3	3
existing Total	7,315	7,060	7,092	6,795	6,434	6,434	6,434	6,287	6,277	6,230	5,884	5,744	5,690	5,360	5,280	5,065	4,714	4,642	4,550	4,483
placeholder																				
PPA.placeholder.renewable.PV	-	-	-	25	75	75	75	75	75	75	88	120	165	215	275	275	275	275	275	290
PPA.placeholder.renewable.GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	21	21	21
PPA.placeholder.Gas	-	-	-	-	600	600	600	865	865	865	865	865	865	865	865	865	865	600	600	600
NVE.placeholder.Gas	-	-	-	-	-	-	-	-	-	-	358	358	358	716	716	1,098	1,648	1,648	1,648	1,648
placeholder Total	-	-	-	25	675	675	675	940	940	940	1,311	1,343	1,388	1,796	1,856	2,238	2,809	2,544	2,544	2,559
proposed																				
PPA.proposed.Renewable.PV	-	-	50	250	250	250	250	250	250	250	250	200	200	200	200	200	200	200	200	200
PPA.proposed.Renewable.BESS	-	-	25	100	100	100	100	100	100	100	100	100	75	75	75	75	75	75	-	-
proposed Total	-	-	75	350	350	350	350	350	350	350	350	300	275	275	275	275	275	275	200	200

H. ENVIRONMENTAL EXTERNALITIES AND NET ECONOMIC BENEFITS

Nevada regulations require NV Energy to consider environmental costs and "net economic benefits" (which are generally termed "economic impacts") when analyzing alternative resource cases.

1. OVERVIEW OF RELEVANT REGULATIONS

The regulations require the Companies to rank its power supply options on the basis of the PWRR and the Present Worth of Societal Costs ("PWSC"). The PWSC of a resource case is defined as the sum of the PWRR plus "environmental costs that are not internalized as private costs to the utility…"[41] Environmental costs are defined by the Commission as "costs, wherever they may occur, that result from harm or risks of harm to the environment after the application of all mitigation measures required by existing environmental regulation or otherwise included in the resource plan."[42] In addition, based upon recent proposals of the Commission, the regulations state that "environmental costs to the State associated with operating and maintaining a supply plan or

41 NAC § 704.937(4).

42 NAC § 704.9359.

demand-side plan must be quantified for air emissions, water and land use and the social cost of carbon as calculated pursuant to subsection 5 of NAC § 704.937 and, if applicable, subsection 6 of that section."[43] Among these potential costs, environmental costs associated with air emissions impacts have typically (and appropriately, given their relative importance) received the most attention in the evaluation of cases, although the recent addition of a requirement to include the social cost of carbon ("SCC") has highlighted the significance of carbon emissions.[44]

The regulations also require NV Energy to assess the "net economic benefits" of cases under certain circumstances, as noted below. "Economic benefits" are often referred to as "economic impacts," so that they are distinguished from other types of benefits. The net economic benefits include both the positive impacts of greater expenditures in Nevada and the negative impacts of higher electricity rates for consumers and businesses that generally accompany greater expenditures.

This section provides quantitative estimates and qualitative assessments that comply with the regulations discussed above.

The Companies retained the services of NERA Economic Consulting ("NERA") to provide analyses of the environmental costs and net economic benefits for the four primary alternative resource cases identified in the 2018 Joint IRP.[45] As discussed above, the cases differ in their acquisition of new generation facilities by the Companies, purchases of existing plants, purchases of renewable energy, and purchases from the market. The Low Carbon case is the "Preferred Plan." Details on NERA's analyses are provided in the NERA report (Technical Appendix Item ECON-12).

2. CARBON DIOXIDE PRICE SCENARIOS

a. BACKGROUND

On October 23, 2015, the U.S. Environmental Protection Agency ("EPA") published the Final Clean Power Plan ("CPP") rule to regulate carbon dioxide ("CO_2") emissions from existing fossil fuel-fired power plants under Section 111(d) of the Clean Air Act. In response to litigation challenging EPA's promulgation of the CPP, on February 9, 2016, the Supreme Court "stayed" the CPP. On March 28, 2017, President Donald Trump signed the Executive Order on Energy

43 NAC § 704.9359, as proposed on April 27, 2018 in connection with Senate Bill No. 65, chapter 383, Statutes of Nevada 2017, at page 2471.

44 Subjection 5 of the draft regulation requires that the Social Cost of Carbon ("SCC") be calculated using the analysis set forth in the "Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis" released by the Interagency Working Group on Social Cost of Greenhouse Gases (hereafter, "Interagency Working Group") in August 2016, the latest report issued by the Interagency Working Group, which was disbanded by President Trump in March 2017. This document is available at https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

45 NERA is a global firm of experts who apply economic, finance, and quantitative principles to complex business and legal challenges. NERA has earned wide recognition for its work in energy, environmental economics and regulation, antitrust, public utilities regulation, transportation, health care, and international trade, among other areas of expertise. References to NERA in this document relate to the authors of the NERA report; the analyses and conclusions in the NERA report represent those of the authors and do not necessarily represent those of NERA or any of its clients.

Independence (E.O. 13783), which disbanded the Interagency Working Group and called for a review of the CPP. On October 16, 2017, EPA formally proposed to repeal the CPP after completing its initial review.[46] The comment period associated with the repeal closed on April 26, 2018.

At this point, it seems very certain that the CPP will not go into effect in 2022 as set out in the current schedule outlined in the Final CPP. Indeed, neither the CPP nor a similar policy is likely to be implemented during the Trump Administration, which will extend at least until the beginning of 2021. Thus, it is sensible to include the possibility of no future climate change regulations as one potential scenario to be analyzed for this filing.

To take into account the possibility of national regulation of greenhouse gas emissions in the future, however, it also seems appropriate to consider a scenario that includes a national cap-and-trade program similar in structure to programs that have been considered by the U.S. Congress and evaluated in prior IRPs. In June 2009, the U.S. House of Representatives passed an economy-wide cap-and-trade program for greenhouse gas ("GHG") emissions, commonly referred to as the "Waxman-Markey Bill" (U.S. House of Representatives 2009), which set goals of reducing GHG emissions by 17 percent below 2005 levels by 2020 and 83 percent below 2005 levels by 2050. Senators John Kerry and Joe Lieberman proposed a similar bill in the U.S. Senate in 2010, but it did not proceed to a vote in the full Senate. The cap-and-trade approach has various well-recognized advantages over a regulatory approach, including more complete incentives to minimize the overall national cost of achieving emission reductions. In addition, compared to a carbon tax, the cap-and-trade approach provides more opportunities to mitigate transition and distributional impacts of carbon policy.

b. SPECIFIC CARBON PRICE TRAJECTORIES AND USE IN IRP ANALYSES

Clearly there is considerable uncertainty regarding the potential future national regulation of CO_2 emissions from existing power plants and the extent to which regulations might impose a "price" on CO_2 emissions. To account for the range of possibilities for future CO_2 policies, NERA developed several alternative CO_2 scenarios, two of which are included in the full set of analyses. The first is the "No Carbon Price" scenario, which assumes that no carbon regulation policy would be put in effect over the analysis period. The second is a "Mid CO_2 Price" scenario, in which a national cap-and-trade program is assumed to be put in place, with a cap consistent with allowance prices assumed to begin in 2025 at $10 per metric ton (2017$) and increase each year at a 5 percent real rate. NERA also developed information for a "Low CO_2 Price" scenario and a "High CO_2 price" scenario, in which the CO_2 price is assumed to begin in 2025 at $5 per metric ton (2017$) and $20 per metric ton (2017$), respectively, and increase each year at the same real interest rate.

NERA developed estimates of the effects of the No Carbon Price scenario and the Mid CO_2 Price scenario on fuel prices (natural gas and coal). NV Energy used these effects on fuel prices, as well as the CO_2 prices, in its modeling of the four primary cases. These differences in CO_2 and fuel prices lead to differences in the generation of various units under each of the four cases. The CO_2

46 See EPA 40 CFR Part 52, p. 48036 https://www.gpo.gov/fdsys/pkg/FR-2017-10-16/pdf/2017-22349.pdf

price trajectories are not relevant for the fifth case, which assumes voters approve Question 3 in November 2018 and the ballot measure is implemented in 2023.

3. ENVIRONMENTAL COSTS FOR CONVENTIONAL AND TOXIC AIR EMISSIONS

NERA uses a damage value approach to develop estimates of the environmental costs in Nevada of conventional and toxic air emissions. This approach begins with the premise that the conceptually correct measure of the value of pollutant emissions is equal to the value of the damages caused by those emissions (assuming no binding cap-and-trade program or other price for emissions). Damages can include effects on health, visibility, and agriculture.[47] The empirical information used in this approach includes information developed by EPA based upon its summaries of research by environmental scientists and economists (although NERA has not verified this information).

Figure NERA–1 presents the estimated environmental costs of conventional and toxic air emissions for the four primary cases. Figure NERA–2 presents similar values for the fifth case based upon passage of Question 3. Both tables include environmental costs for emissions controlled to meet National Ambient Air Quality Standards ("NAAQS") as well as emissions related to requirements of the Mercury and Air Toxics Standards ("MATS") issued by EPA in 2011.[48] These environmental costs were modeled for both the No Carbon Price and Mid CO_2 Price scenarios described above.

Based on the NAAQS, NERA included values for emissions of nitrogen oxides ("NO_X"), particulate matter ("PM"), volatile organic compounds ("VOC"), carbon monoxide ("CO"), and sulfur dioxide ("SO_2"). VOC environmental costs are estimated to be $0 because they do not contribute to ambient ozone concentrations in Nevada, as discussed in the NERA report. CO is not monetized because the necessary site-specific data were unavailable; however, CO emissions projections are included in the NERA report. As noted above and discussed in the NERA report, the national SO_2 cap is not expected to be binding and thus costs from SO_2 emissions are evaluated based on damage values like other air emissions (rather than modeled as covered by a cap-and-trade program as in some past IRPs). Based on their inclusion in the MATS regulation, emissions of mercury and hydrogen chloride ("HCl") are also included. The MATS regulation uses particulate matter ("PM") emissions as a proxy for non-mercury metallic air toxics, but this element of the MATS regulation does not lead to additional environmental costs because PM emissions are already included based upon the NAAQS. HCl is not monetized because EPA does not provide the relevant information in the MATS regulatory impact analysis; however, HCl emission projections are included in the NERA report.

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47 Given data limitations, NERA did not quantify non-health welfare effects but indicated that they expect non-health costs to be small relative to the health damages.

48 The environmental values per ton of air emissions are based in part on estimates developed by the EPA, as discussed in the NERA report. The authors of the NERA report have not evaluated the scientific and economic analyses that underlie the EPA estimates and do not endorse the values.

FIGURE NERA–1. PRESENT VALUES OF ENVIRONMENTAL COSTS FOR CONVENTIONAL AIR EMISSIONS AND TOXICS FOR PRIMARY CASES (2019$ MILLIONS)

	Low Carbon	All Market	Development	Renewable
NOx				
No Carbon Price	$6.24	$6.42	$6.21	$6.24
Mid CO2 Price	$6.28	$6.45	$6.26	$6.28
PM				
No Carbon Price	$154.60	$163.07	$151.64	$154.60
Mid CO2 Price	$154.39	$162.66	$151.17	$154.40
VOC				
No Carbon Price	$0.00	$0.00	$0.00	$0.00
Mid CO2 Price	$0.00	$0.00	$0.00	$0.00
CO				
No Carbon Price	-	-	-	-
Mid CO2 Price	-	-	-	-
SO2				
No Carbon Price	$9.84	$10.00	$9.95	$9.87
Mid CO2 Price	$10.30	$10.52	$10.42	$10.33
Mercury				
No Carbon Price	$0.00	$0.00	$0.00	$0.00
Mid CO2 Price	$0.00	$0.00	$0.00	$0.00
HCl				
No Carbon Price	-	-	-	-
Mid CO2 Price	-	-	-	-
Total				
No Carbon Price	$170.68	$179.49	$167.81	$170.71
Mid CO2 Price	$170.98	$179.63	$167.85	$171.01

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by the Companies.

Total may differ from the sum of the rows due to independent rounding.

"-" denotes that the environmental costs of the air emission are not monetized.

FIGURE NERA–2. PRESENT VALUES OF ENVIRONMENTAL COSTS FOR CONVENTIONAL AIR EMISSIONS AND TOXICS FOR Q3 ALTERNATIVE (2019$ MILLIONS)

	Q3
NOx	$2.09
PM	$42.19
VOC	$0.00
CO	-
SO2	$2.59
Mercury	$0.00
HCl	-
Total	$46.86

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by the Companies.

All values for the Q3 Alternative are based on the Mid CO_2 Price scenario only. Since the Mid CO_2 Price scenario assumes a binding cap in 2025, and the analysis period for the Q3 Alternative ends in 2023, using the No Carbon Price scenario as an alternative would have no effect on the results.

Total may differ from the sum of the rows due to independent rounding.

"-" denotes that the environmental costs of the air emission are not monetized.

Figure NERA–3 summarizes the environmental costs of conventional air emissions and air toxics for the four primary cases relative to the Low Carbon Case. The environmental costs of conventional and toxic air emissions are similar across the cases under both the No Carbon Price scenario and the Mid CO_2 Price scenario. These results indicate that the Low Carbon and Renewable cases have virtually the same conventional and toxic air emissions costs. In contrast, the Development case has noticeably smaller costs and the All Market case has noticeably larger costs than these other two cases.

FIGURE NERA - 3. PRESENT VALUES OF THE DIFFERENCES IN ENVIRONMENTAL COSTS OF CONVENTIONAL AIR EMISSIONS AND TOXICS FOR PRIMARY CASES FOR 2019-2048, RELATIVE TO LOW CARBON CASE (2019$ MILLIONS)

	Low Carbon	All Market	Development	Renewable
No Carbon Price	-	$8.81	-$2.87	$0.03
Mid CO2 Price	-	$8.65	-$3.13	$0.03

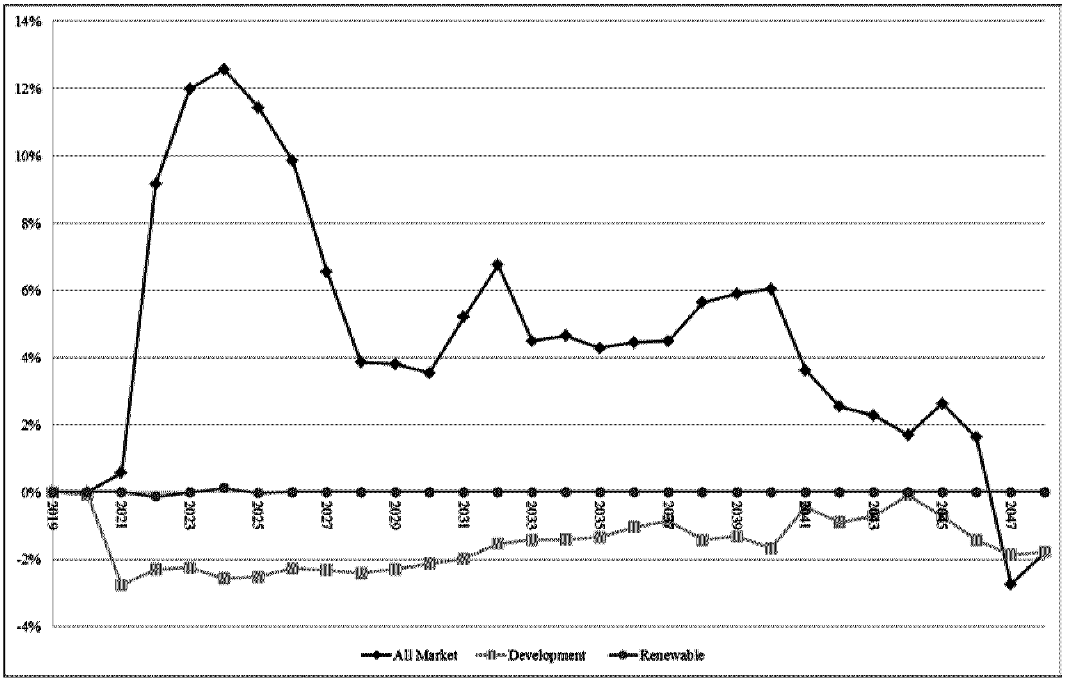
Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by NV Energy.

4. ENVIRONMENTAL COSTS FOR RELEVANT CARBON DIOXIDE EMISSIONS BASED ON SCC VALUES DEVELOPED BY THE INTERAGENCY WORKING GROUP

NERA developed estimates of the environmental costs of CO_2 emissions based on the SCC values developed by the Interagency Working Group and reported in its August 2016 report, as called for in the proposed Commission regulation implementing Senate Bill 65. Values were developed for the CO_2 emissions related to the various cases for the No Carbon Price and Mid CO_2 Price scenarios.

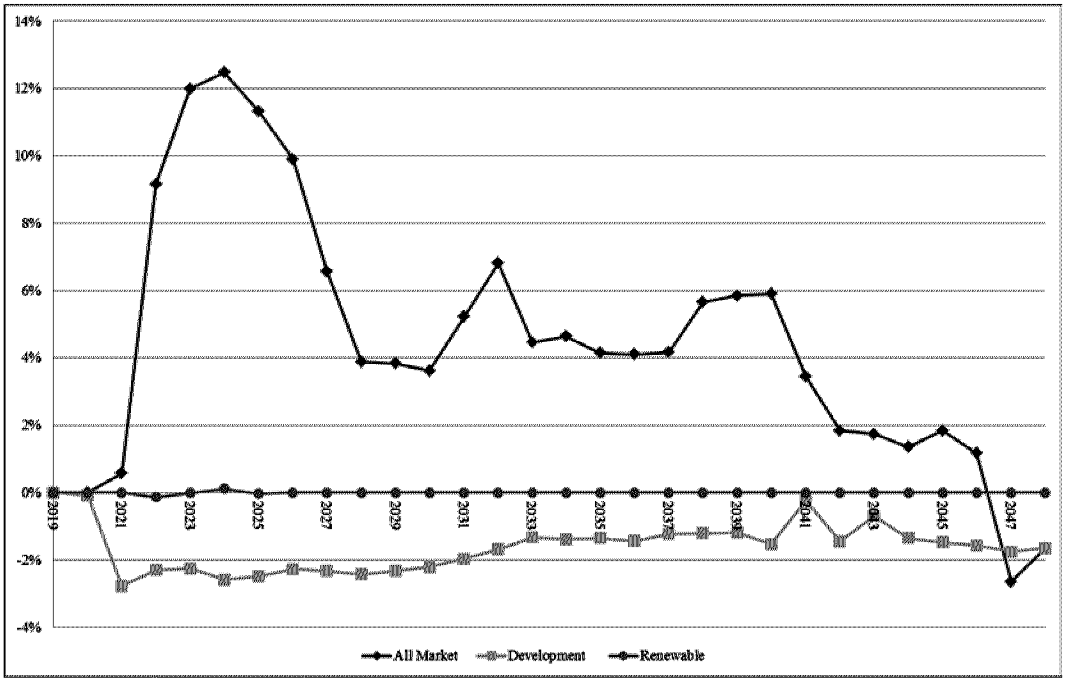
Figure NERA–4 and Figure NERA–5 below summarize the CO_2 emissions estimates underlying the social costs of carbon analysis. The below figures include emissions information for the four primary cases relative to the Low Carbon Case for the No Carbon Price and Mid CO_2 Price scenarios.

FIGURE NERA - 4. NO CARBON PRICE SCENARIO PERCENTAGE DIFFERENCE IN CARBON DIOXIDE EMISSIONS FOR THE PRIMARY CASES RELATIVE TO THE LOW CARBON CASE, 2019-2048 (2019$ MILLIONS)



Notes: All values are percentage differences relative to the emissions for the Low Carbon Case under the No Carbon Price Scenario.

FIGURE NERA - 5. MID CO_2 PRICE SCENARIO PERCENTAGE DIFFERENCE IN CARBON DIOXIDE EMISSIONS FOR THE PRIMARY CASES RELATIVE TO THE LOW CARBON CASE, 2019-2048 (2019$ MILLIONS)



Notes: All values are percentage differences relative to the emissions for the Low Carbon Case under the Mid CO_2 Price Scenario.

As emphasized by the Interagency Working Group in its August 2016 Report and noted in the NERA report, developing estimates of the SCC is extraordinarily uncertain because of the enormous uncertainties regarding the potential effects of CO_2 and other greenhouse gas emissions. NERA has in the past referred to these costs based on the SCC as illustrative and presented them separately to reflect their highly uncertain nature, and NERA has continued that approach here. Moreover, NERA has also presented values both for global damages (as presented in the 2016 report by the Interagency Working Group) and for U.S. damages (as provided in an earlier report by the Interagency Working Group and presented in prior NERA reports). Note that any SCC values only apply to emissions that are not subject to a binding cap-and-trade program, since NERA assumes that under a binding cap-and-trade program, the prices in that market "internalize" the externalities associated with the emissions. These assumptions are consistent with the proposed regulation, as discussed in the NERA report. Thus, NV Energy's CO_2 emissions are not included for the Mid CO_2 Price scenario after 2024, since the cap-and-trade program is presumed to apply to years 2025 and beyond.

The uncertainties surrounding estimation of SCC values include uncertainties regarding the nature and extent of potential adverse effects associated with CO_2 emissions, the valuation of these effects, and the appropriate discount rate to be used to calculate the present value of future damages from a ton of CO_2 emitted in a given year. As noted, due to these and other uncertainties, NERA

has previously referred to the environmental costs of CO_2 emissions based on SCC values as illustrative.

The Interagency Working Group provided global SCC damage estimates for three discount rates—2.5 percent, 3 percent, and 5 percent—using the average of the damages distribution for these discount rates. It also provided a fourth set of global damage values based on the 3 percent discount rate and the 95th percentile of the damages distribution, which it noted are designed "to represent the higher-than-expected impacts from temperature change further out in the tails of the SCC distribution." The values recommended by the Interagency Group in August 2016 for use in Federal regulatory analyses covered a very large range and, indeed, the full range of values reported by the Interagency Group was much greater than the four sets of SCC estimates referenced above.

Figure NERA–6 shows the range of CO_2 costs (as present values) based on the No Carbon Price and Mid CO_2 Price scenarios for the four primary expansion Cases using the four sets of SCC damage estimates. Figure NERA–7 shows the range of CO_2 costs (as present values) for the fifth case, the Q3 Alternative using the four sets of SCC damage estimates. The lowest values reflect a 5 percent discount rate (and the average of the damages distribution), while the highest values reflect a 3 percent discount rate and the 95th percentile of the damages distribution. The figure shows ranges using the global SCC values as well as adjusting the global values to reflect damages in the United States.[49] Note that NERA has in prior IRP's noted that these values are not comparable to the environmental costs calculated for other emissions for several reasons: (a) the illustrative CO_2 costs are more uncertain partly because they are based upon impacts in the distant future; (b) the illustrative CO_2 costs are based on different discount rates than the private (NV Energy) discount rates used to calculate the present value of other environmental costs; and (c) the illustrative CO_2 costs are based upon either global or U.S. damages rather than Nevada-specific damages. Additional information on NERA's methodology for estimating illustrative CO_2 costs using SCC values developed by the Interagency Working Group is provided in the NERA report.

49 The Interagency Working Group in its February 2010 report indicated that U.S. damages should be calculated using a range from 7 percent to 23 percent of the global values. This analysis uses the midpoint (15 percent) from that range.

FIGURE NERA - 6. PRESENT VALUES OF ILLUSTRATIVE ESTIMATES OF ENVIRONMENTAL COSTS FOR CARBON DIOXIDE EMISSIONS FOR PRIMARY CASES, 2019-2048 (2019$ MILLIONS)

	Low Carbon			All Market			Development			Renewable		
United States												
No Carbon Price	$423	to	$5,067	$444	to	$5,316	$417	to	$4,991	$423	to	$5,067
Mid CO_2 Price	$122	to	$1,300	$128	to	$1,366	$120	to	$1,279	$122	to	$1,299
Global												
No Carbon Price	$2,821	to	$33,782	$2,961	to	$35,440	$2,778	to	$33,272	$2,821	to	$33,782
Mid CO_2 Price	$813	to	$8,664	$854	to	$9,106	$801	to	$8,527	$813	to	$8,662

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 based on values reported by Interagency Group (2016). Minimum values reflect a 5 percent discount rate and the average of the damages distribution, while maximum values reflect a 3 percent discount rate and the 95th percentile of the damages distribution.

U.S. costs are calculated as 15 percent of global costs (the midpoint of the suggested range in Interagency Group 2010).

FIGURE NERA - 7. PRESENT VALUES OF ILLUSTRATIVE ESTIMATES OF ENVIRONMENTAL COSTS FOR CARBON DIOXIDE EMISSIONS FOR Q3 ALTERNATIVE, 2019-2023 (2019$ MILLIONS)

	Q3		
United States			
SCC	$110	to	$1,161
Global			
SCC	$734	to	$7,743

9. Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 based on values reported by Interagency Group (2016). Minimum values reflect a 5 percent discount rate and the average of the damages distribution, while maximum values reflect a 3 percent discount rate and the 95th percentile of the damages distribution. All values for the Q3 Alternative are based on the Mid CO_2 Price scenario only. Since the Mid CO_2 Price scenario assumes a binding cap in 2025, and the analysis period for the Q3 alternative ends in 2023, using the No Carbon Price scenario as an alternative would have no effect on the results.

U.S. costs are calculated as 15 percent of global costs (the midpoint of the suggested range in Interagency Group 2010).

Figure NERA–8 shows the differences relative to the Low Carbon case (the Preferred Plan) of the illustrative estimates of the environmental costs of CO_2 emissions using SCC values under the No Carbon Price and Mid CO_2 Price scenarios. Under both carbon price scenarios, the Low Carbon case and the Renewable case have very similar SCC costs. In contrast, the Development case has noticeably lower SCC costs and the All Market case has noticeably higher costs than these other two cases.

FIGURE NERA - 8. DIFFERENCES IN PRESENT VALUES OF ILLUSTRATIVE ESTIMATES OF ENVIRONMENTAL COSTS FOR CARBON DIOXIDE EMISSIONS FOR PRIMARY CASES FOR 2019-2048, RELATIVE TO THE LOW CARBON (2019$ MILLIONS)

	Low Carbon	All Market		Development		Renewable	
United States							
No Carbon Price	-	$21 to	$249	-$77 to	-$6	$0 to	$0
Mid CO_2 Price	-	$6 to	$66	-$20 to	-$2	$0 to	$0
Global							
No Carbon Price	-	$140 to	$1,657	-$511 to	-$43	-$1 to	$0
Mid CO_2 Price	-	$40 to	$442	-$137 to	-$12	-$2 to	$0

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 based on values reported by Interagency Group (2016). Minimum values reflect a 5 percent discount rate and the average of the damages distribution, while maximum values reflect a 3 percent discount rate and the 95th percentile of the damages distribution. U.S. values are calculated as 15 percent of global values, the midpoint of the suggested range in Interagency Working Group 2010). Total may differ from the sum of the rows due to independent rounding.

Source: NERA calculations as explained in text

5. OTHER ENVIRONMENTAL EFFECTS

Water Quality, Solid Waste and Land Use

NERA considered three other categories of environmental impacts: (1) water quality; (2) solid waste disposal, including sludge and ash disposal; and (3) land use. For each category, NERA considered whether or not there might be significant differences in environmental costs among the four primary cases. NERA concluded than any cost differences were likely to be highly site-specific and not likely to be significant relative to the estimated environmental costs associated with air emissions.

<u>Additional Costs of Water Consumption</u>

NERA estimated the costs of water consumption by NV Energy that are not included in the PWRR. These additional costs are based upon current information related to water use from wells owned by NV Energy and do not include water that is leased or purchased, because the value of leased or purchased water is included in the PWRR. Moreover, no additional water costs are calculated for power purchased by NV Energy through contracts, renewable power purchase agreements, or spot market transactions because NERA assumes that all water costs are included in the prices that NV Energy pays and thus are included in the PWRR.

Figure NERA–8 shows the estimated additional costs of water consumption (*i.e.*, the added costs beyond those already included in the PWRR) for the four resource cases.

FIGURE NERA - 9. PRESENT VALUE OF ADDITIONAL WATER COST FOR PRIMARY CASES, 2019-2048 (2019$ MILLIONS)

	Low Carbon	All Market	Development	Renewable
No Carbon Price	$10.8	$11.8	$10.4	$10.7
Mid CO_2 Price	$10.5	$11.5	$10.1	$10.4

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by NV Energy.

Figure NERA–10 provides values for the fifth case in which Question 3 is approved by voters. As noted, these estimates are not comparable to those for the four primary cases.

FIGURE NERA - 10. PRESENT VALUE OF ADDITIONAL WATER COST FOR Q3 ALTERNATIVE, 2019-2048 (2019$ MILLIONS)

	Q3
Additional Water Cost	$5.8

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by NV Energy.

All values for the Q3 Alternative are based on the Mid CO_2 Price scenario only. Since the Mid CO_2 Price scenario assumes a binding cap in 2025, and the analysis period for the Q3 Alternative ends in 2023, using the No Carbon Price scenario as an alternative would have no effect on the results.

Figure NERA–11 compares the present value of additional water costs relative to the Low Carbon Case. The differences in additional water costs reflect the differences over the four primary expansion cases in the projected monthly generation for the plants owned by NV Energy that consume water from their own wells. The differences in additional water costs among the cases are small, particularly for the Development and Renewable cases. The All Market case has noticeably larger water costs than the other three cases.

FIGURE NERA–11. PRESENT VALUE OF DIFFERENCES IN ADDITIONAL WATER COSTS FOR PRIMARY CASES RELATIVE TO LOW CARBON CASE, 2019-2048 (2019$ MILLIONS)

	Low Carbon	All Market	Development	Renewable
No Carbon Price	-	$1.1	-$0.4	-$0.1
Mid CO_2 Price	-	$1.0	-$0.4	-$0.1

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra. Real annual values were converted to nominal annual values using annual inflation rate information, as provided by the Companies.

6. PRESENT WORTH OF SOCIETAL COST

Figure NERA–12 and Figure NERA–13 provide information on the PWSC for the four primary cases under the No Carbon Price. Figure NERA–14 and Figure NERA–15 provide information on the PWSC for the four primary cases under the Mid CO_2 Price scenarios. As noted above, PWSC is defined as the sum of the PWRR and environmental costs. The environmental costs are calculated in two ways: (1) the sum of air emissions costs and additional water costs; and (2) the sum of air emissions costs, additional water costs and the illustrative SCC calculations. The figures also show the net PWSC relative to the Preferred Plan, the Low Carbon case.

For both CO_2 policy scenarios, the Low Carbon and the Renewable have very similar PWSC. The Development case has a somewhat larger PWRR than the Low Carbon and Renewable cases, but lower environmental costs. When the illustrative SCC estimates are included as part of the PWSC, the relative PWSC rank among the Low Carbon, Renewable, and Development cases varies depending on consideration of the low or high ends of the illustrative SCC range. This indicates that the difference in PWSC among these three cases is potentially small, though highly uncertain when considering the social costs of carbon. The All Market case has the highest PWSC among the four primary cases as it has both the highest PWRR and the greatest environmental costs.

FIGURE NERA–12. PRESENT WORTH OF SOCIETAL COSTS FOR THE NO CARBON PRICE SCENARIO FOR THE PRIMARY CASES, 2019-2048 (2019$ MILLIONS)

	Low Carbon			All Market			Development			Renewable		
PWRR	$22,261.8			$22,356.6			$22,327.7			$22,240.1		
Conventional Air Emission Costs	$170.7			$179.5			$167.8			$170.7		
Additional Water Costs	$10.8			$11.8			$10.4			$10.7		
PWSC w/o SCC	$22,443.2			$22,547.9			$22,505.9			$22,421.5		
Illustrative Social Costs of Carbon	$423.1	to	$33,782.4	$444.1	to	$35,439.5	$416.7	to	$33,271.7	$423.1	to	$33,781.6
PWSC w/ SCC	$22,866.4	to	$56,225.7	$22,992.0	to	$57,987.4	$22,922.6	to	$55,777.6	$22,844.6	to	$56,203.1

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.
The illustrative SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution using United States damages only, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution using Global damages.

FIGURE NERA–13. PRESENT WORTH OF SOCIETAL COSTS FOR THE NO CARBON PRICE SCENARIO FOR THE PRIMARY CASES RELATIVE TO THE LOW CARBON CASE, 2019-2048 (2019$ MILLIONS)

	Low Carbon	All Market			Development			Renewable		
PWRR	-	$94.7			$65.9			-$21.7		
Conventional Air Emission Costs	-	$8.8			-$2.9			$0.0		
Additional Water Costs	-	$1.1			-$0.4			-$0.1		
PWSC w/o SCC	-	$104.6			$62.6			-$21.8		
Illustrative Social Costs of Carbon	-	$21.0	to	$1,657.1	-$6.5	to	-$510.7	$0.0	to	-$0.8
PWSC w/ SCC	-	$125.6	to	$1,761.7	$56.2	to	-$448.0	-$21.8	to	-$22.6

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048 using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.

FIGURE NERA–14. PRESENT WORTH OF SOCIETAL COSTS FOR THE MID CO_2 PRICE SCENARIO FOR THE PRIMARY CASES, 2019-2048 (2019$ MILLIONS)

	Low Carbon	All Market	Development	Renewable
PWRR	$23,504.0	$23,659.5	$23,532.8	$23,482.1
Conventional Air Emission Costs	$171.0	$179.6	$167.8	$171.0
Additional Water Costs	$10.5	$11.5	$10.1	$10.4
PWSC w/o SCC	$23,685.5	$23,850.6	$23,710.8	$23,663.6
Illustrative Social Costs of Carbon	$122.0 to $8,663.7	$128.0 to $9,105.6	$120.1 to $8,527.1	$122.0 to $8,662.2
PWSC w/ SCC	$23,807.5 to $32,349.2	$23,978.6 to $32,956.2	$23,830.9 to $32,237.9	$23,785.6 to $32,325.8

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.
The illustrative SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution using United States damages only, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution using Global damages.

FIGURE NERA–15. PRESENT WORTH OF SOCIETAL COSTS FOR THE MID CO_2 PRICE SCENARIO FOR THE PRIMARY CASES RELATIVE TO THE LOW CARBON CASE, 2019-2048 (2019$ MILLIONS)

	Low Carbon	All Market	Development	Renewable
PWRR	-	$155.5	$28.8	-$21.8
Conventional Air Emission Costs	-	$8.6	-$3.1	$0.0
Additional Water Costs	-	$1.0	-$0.4	-$0.1
PWSC w/o SCC	-	$165.1	$25.3	-$21.9
Illustrative Social Costs of Carbon	-	$6.0 to $441.9	-$1.9 to -$136.6	$0.0 to -$1.5
PWSC w/ SCC	-	$171.1 to $607.0	$23.5 to -$111.3	-$21.9 to -$23.4

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.
The illustrative SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution using United States damages only, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution using Global damages.

Figure NERA–16 provides information on the PWSC for the Q3 Alternative scenario. Note that this alternative is only evaluated through 2023 and should not be compared to other cases.

FIGURE NERA–16. PRESENT WORTH OF SOCIETAL COSTS FOR THE Q3 ALTERNATIVE, 2019-2023 (2019$ MILLIONS)

	Q3
PWRR	$5,679.8
Conventional Air Emission Costs	$46.9
Additional Water Costs	$5.8
PWSC w/o SCC	$5,732.5
Illustrative Social Costs of Carbon	$110.2 to $7,743.3
PWSC w/ SCC	$5,842.7 to $13,475.8

Notes: All values are present values as of January 1, 2019 in millions of 2019 dollars for the period 2019-2048. For conventional air emissions and water cost present values are calculated using nominal annual discount rates of 7.95 percent for Nevada Power and 6.65 percent for Sierra.
The illustrative SCC ranges include minimum values that reflect a 5 percent discount rate and the average of the damages distribution using United States damages only, and maximum values that reflect a 3 percent discount rate and the 95th percentile of the damages distribution using Global damages.

All values for the Q3 Alternative are based on the Mid CO_2 Price scenario only. Since the Mid CO_2 Price scenario assumes a binding cap in 2025, and the analysis period for the Q3 Alternative ends in 2023, using the No Carbon Price scenario as an alternative would have no effect on the results.

7. ECONOMIC IMPACTS

The NERA economic impact analysis uses the economic model developed by Regional Economic Models, Inc. ("REMI") to provide comprehensive estimates of economic impacts for the alternative resource cases, including the positive effects of expenditures in Nevada as well as the potential negative effects of greater electricity rates under more expensive cases. NV Energy provided NERA with additional information on electricity revenue forecasts, which enabled the development of both the positive economic impacts of expenditures associated with the resource cases and the negative economic impacts of the electricity rate increases associated with these expenditures.

As explained in detail in the NERA report, the REMI model provides a detailed representation of the Nevada economy. The core of the model is a set of input-output (I/O) relationships among different industries, which allow one to estimate how changes in demand or supply in each relevant industry will affect all other industries. The I/O formulation also takes into account "economic leakage," which is the extent to which expenditures in any industry lead to imported goods from outside the economy (and thus do not have direct "multiplier" effects in Nevada). REMI also provides estimates of the impacts on Nevada of higher electric rates when all the feedback mechanisms in the economy are taken into account (*e.g.*, changes in wages that result from changes in economic activity).

Simulations of the economy in REMI require a "baseline" scenario to which "alternative" scenarios can be compared. The All Market Case under the No Carbon Price scenario is assumed to be the baseline or reference scenario, as this case involves the least change to the generation fleet and thus most closely approximates what resources might be implicit in REMI's reference scenario. The economic impact analysis is conducted over the period from 2019 to 2048, which is

the period over which the Companies forecast electricity revenue. NERA developed economic impact assessments for the four primary cases under both the No Carbon Price scenario and the Mid CO_2 Price scenario. Although the All Market Case is assumed to be the baseline or reference scenario for purposes of the REMI modeling of expenditures, we present results relative to the preferred case, the Low Carbon Case. These REMI results are presented first under the No Carbon Price scenario and then for the Mid CO_2 Price scenario, as expenditures differ somewhat under these two carbon price scenarios.

Figure NERA–17 shows the average annual expenditures in Nevada for the economic impacts analysis under the No Carbon Price scenario. As discussed in the NERA report, the values exclude certain categories of expenditures, such as spot market purchases by the Companies, because those expenditures are assumed to flow to power producers outside Nevada (hence they would not generate positive economic impacts in Nevada) Given uncertainty related to the location of expenditures related to the Companies' open positions, the economic impact analysis assumes that 50 percent of open position expenditures would occur within the state and that 50 percent of open position expenditures would occur outside the state of Nevada.

FIGURE NERA – 17. NO CARBON PRICE SCENARIO AVERAGE ANNUAL RELEVANT EXPENDITURES FOR PRIMARY CASES (2019$ MILLIONS), 2019-2048

	All Market	Low Carbon	Development	Renewable
Construction	$489	$543	$562	$542
Fuel	$751	$722	$711	$722
O&M	$229	$276	$283	$277
Total	$1,468	$1,542	$1,555	$1,541

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–18 shows the differences in average annual expenditures over the period from 2019 to 2048 for each case relative to the REMI reference case (All Market Case under the No Carbon Price scenario). Only expenditures that occur in Nevada are included in these calculations because of the focus on estimating the economic impacts of alternative cases in Nevada. Note that these average annual values do not reflect differences over the 30-year period.

FIGURE NERA–18. NO CARBON PRICE SCENARIO AVERAGE ANNUAL RELEVANT EXPENDITURES FOR PRIMARY CASES COMPARED TO ALL MARKET CASE (2019$ MILLIONS), 2019-2048

	All Market	Low Carbon	Development	Renewable
Construction	-	$54	$73	$53
Fuel	-	-$28	-$40	-$28
O&M	-	$48	$54	$48
Total	-	$74	$87	$73

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–19 shows the average annual values of the Companies' electricity revenue requirements for 2019-2048, apportioned by customer class, under the No Carbon Price scenario.

FIGURE NERA–19. NO CARBON PRICE SCENARIO AVERAGE ANNUAL ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS FOR PRIMARY CASES (2019$ MILLIONS), 2019-2048

	All Market	Low Carbon	Renewables	Development
Total	**$1,561**	**$1,552**	**$1,551**	**$1,554**
Residential	$651	$647	$646	$648
Commercial	$407	$405	$404	$405
Industrial	$503	$501	$500	$501

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–20 shows differences in average annual values of electricity revenue for each case relative to the All Market case (the REMI baseline). Note that these average annual values do not reflect differences over the 30-year period.

FIGURE NERA–20. NO CARBON PRICE SCENARIO ELECTRICITY REVENUE BY CUSTOMER CLASS FOR PRIMARY CASES COMPARED TO ALL MARKET CASE (2019$ MILLIONS), 2019-2048

	All Market	Low Carbon	Renewables	Development
Total	-	**-$9**	**-$10**	**-$6**
Residential	-	-$4	-$5	-$3
Commercial	-	-$2	-$2	-$1
Industrial	-	-$3	-$3	-$2

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

REMI modeling takes as inputs the annual values for expenditures and electricity revenues, and develops economic impacts for the four primary expansion cases that change over time. For each of the four resource cases, Figure NERA–21 displays annual estimates of changes in future Nevada gross state product, personal income, state and local tax revenue and employment relative to 2018. Note that as noted, this first set of results is based on the No Carbon Price scenario. REMI projects substantial economic growth in Nevada over the period from 2019 to 2048 across the various economic impacts metrics for each of the resource cases. In the case of employment, for example, Nevada is projected to increase total jobs by more than 200,000 from 2019 to 2048.

FIGURE NERA - 21. NO CARBON PRICE SCENARIO NEVADA ECONOMIC IMPACTS UNDER THE FOUR PRIMARY RESOURCE CASES

	Nevada Economic Impacts Compared to 2018					
	2019	2021	2023	2028	2038	2048
Low Carbon						
Gross State Product (millions of 2019 dollars)	4,196	11,707	19,994	41,355	97,297	170,066
Personal Income (millions of 2019 dollars)	4,556	11,806	19,174	37,250	87,399	160,582
State & Local Tax Revenue (millions of 2019 dollars)	469	1,216	1,975	3,837	9,002	16,540
Employment (total jobs)	18,800	22,064	20,715	39,144	110,599	202,697
All Market						
Gross State Product (millions of 2019 dollars)	4,196	11,401	19,622	41,662	97,279	169,768
Personal Income (millions of 2019 dollars)	4,556	11,603	18,917	37,432	87,379	160,389
State & Local Tax Revenue (millions of 2019 dollars)	469	1,195	1,948	3,855	9,000	16,520
Employment (total jobs)	18,800	18,983	17,878	41,669	110,462	200,885
Development						
Gross State Product (millions of 2019 dollars)	4,197	11,868	20,003	41,344	97,296	170,071
Personal Income (millions of 2019 dollars)	4,556	11,912	19,186	37,245	87,400	160,591
State & Local Tax Revenue (millions of 2019 dollars)	469	1,227	1,976	3,836	9,002	16,541
Employment (total jobs)	18,804	23,488	20,688	39,020	110,599	202,768
Renewable						
Gross State Product (millions of 2019 dollars)	4,196	11,707	19,989	41,356	97,297	170,065
Personal Income (millions of 2019 dollars)	4,556	11,806	19,172	37,251	87,399	160,582
State & Local Tax Revenue (millions of 2019 dollars)	469	1,216	1,975	3,837	9,002	16,540
Employment (total jobs)	18,800	22,064	20,696	39,151	110,594	202,694

Note: The All Market case under the No Carbon Price scenario is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other three cases are in comparison to this baseline case. Employment values in REMI include full time and part time jobs.

Source: REMI; NERA calculations as explained in text.

Growth in the Nevada economy is projected to be very similar under the four primary expansion cases, although there are some differences in economic impacts in some years. As shown in Figure NERA–22, The Low Carbon case and the Renewable case have virtually the same economic impacts. In contrast, the growth in the Nevada economy would be noticeably greater under the Development case in one year (2021) and noticeably smaller under the All Market case under the majority of the years (on the order of 2,000 to 3,000 jobs).

FIGURE NERA - 22. NO CARBON PRICE SCENARIO NEVADA ECONOMIC IMPACTS FOR THE PRIMARY CASES COMPARED TO LOW CARBON CASE

	Nevada Economic Impacts Compared to 2018					
	2019	**2021**	**2023**	**2028**	**2038**	**2048**
Low Carbon						
Gross State Product (millions of 2019 dollars)	-	-	-	-	-	-
Personal Income (millions of 2019 dollars)	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2019 dollars)	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-
All Market						
Gross State Product (millions of 2019 dollars)	0	-306	-371	308	-19	-298
Personal Income (millions of 2019 dollars)	0	-203	-257	182	-20	-193
State & Local Tax Revenue (millions of 2019 dollars)	0	-21	-26	19	-2	-20
Employment (total jobs)	0	-3,081	-2,837	2,525	-137	-1,812
Development						
Gross State Product (millions of 2019 dollars)	1	161	9	-11	-1	5
Personal Income (millions of 2019 dollars)	0	106	12	-5	1	9
State & Local Tax Revenue (millions of 2019 dollars)	0	11	1	-1	0	1
Employment (total jobs)	4	1,424	-27	-124	0	71
Renewable						
Gross State Product (millions of 2019 dollars)	0	0	-5	2	0	-1
Personal Income (millions of 2019 dollars)	0	0	-2	1	-1	-1
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	0	0	0
Employment (total jobs)	0	0	-19	7	-5	-3

Note: The All Market case under the No Carbon Price scenario is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other three cases are in comparison to the All Market case; employment values include full time and part time jobs.

Source: REMI; NERA calculations as explained in text.

The following tables provide the equivalent inputs and results for the Mid CO_2 Price scenario. Resource additions and capital expenditures are expected to be identical between the No Carbon Price and Mid CO_2 Price scenarios. The two scenarios differ by fuel prices and CO_2 prices, which impacts the production cost and dispatch of generating units. Even accounting for these differences, the two scenarios are very similar with respect to their impacts on potential economic impacts of the cases on the Nevada economy. Figure NERA–23 presents average annual relevant expenditures in Nevada under the Mid CO_2 Price scenario.

FIGURE NERA - 23. MID CO_2 PRICE SCENARIO AVERAGE ANNUAL RELEVANT EXPENDITURES FOR THE PRIMARY CASES (2019$ MILLIONS), 2019-2048

	All Market	Low Carbon	Development	Renewable
Construction	$489	$543	$562	$542
Fuel	$775	$746	$733	$746
O&M	$229	$277	$283	$277
Total	$1,492	$1,565	$1,577	$1,565

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars

Figure NERA–24 compares the average annual relevant expenditures in each primary case to those in the All Market case.

FIGURE NERA - 24. MID CO_2 PRICE SCENARIO AVERAGE ANNUAL RELEVANT EXPENDITURES FOR THE PRIMARY CASES COMPARED TO ALL MARKET (2019$ MILLIONS), 2019-2048

	All Market	Low Carbon	Development	Renewable
Construction	-	$54	$73	$53
Fuel	-	-$29	-$42	-$29
O&M	-	$48	$54	$48
Total	-	$73	$85	$73

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars

Figure NERA–25 presents the electricity revenue requirements apportioned by customer class under the Mid CO_2 Price scenario.

FIGURE NERA - 25. MID CO_2 PRICE SCENARIO AVERAGE ANNUAL ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS FOR THE PRIMARY CASES (2019$ MILLIONS), 2019-2048

	All Market	Low Carbon	Renewables	Development
Total	**$1,693**	**$1,680**	**$1,679**	**$1,679**
Residential	$706	$700	$700	$700
Commercial	$441	$438	$438	$438
Industrial	$546	$542	$542	$542

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

NERA Figure–26 compares the electricity revenue requirements in each case to those in the All Market case.

FIGURE NERA - 26. MID CO_2 PRICE SCENARIO ELECTRICITY REVENUE BY CUSTOMER CLASS FOR THE PRIMARY CASES COMPARED TO ALL MARKET CASE (2019$ MILLIONS), 2019-2048

	All Market	Low Carbon	Renewables	Development
Total	-	**-$13**	**-$14**	**-$1**
Residential	-	-$6	-$7	-$7
Commercial	-	-$3	-$3	-$3
Industrial	-	-$4	-$4	-$4

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–27 presents REMI model results for the Mid CO_2 Price scenario. The long-term impact on the Nevada economy is not materially affected by the different carbon scenarios. In all cases, employment is expected to grow in Nevada by more than 200,000 jobs from 2019 to 2048.

FIGURE NERA - 27. MID CO_2 PRICE SCENARIO NEVADA ECONOMIC IMPACTS UNDER THE FOUR PRIMARY RESOURCE CASES

	Nevada Economic Impacts Compared to 2018					
	2019	2021	2023	2028	2038	2048
Low Carbon						
Gross State Product (millions of 2019 dollars)	4,196	11,707	19,994	41,357	97,291	170,018
Personal Income (millions of 2019 dollars)	4,556	11,806	19,174	37,245	87,369	160,523
State & Local Tax Revenue (millions of 2019 dollars)	469	1,216	1,975	3,836	8,999	16,534
Employment (total jobs)	18,800	22,064	20,715	39,066	110,228	202,228
All Market						
Gross State Product (millions of 2019 dollars)	4,196	11,401	19,622	41,664	97,272	169,722
Personal Income (millions of 2019 dollars)	4,556	11,603	18,917	37,425	87,348	160,333
State & Local Tax Revenue (millions of 2019 dollars)	469	1,195	1,948	3,855	8,997	16,514
Employment (total jobs)	18,800	18,983	17,878	41,569	110,077	200,447
Development						
Gross State Product (millions of 2019 dollars)	4,197	11,868	20,003	41,347	97,290	170,025
Personal Income (millions of 2019 dollars)	4,556	11,912	19,186	37,241	87,370	160,533
State & Local Tax Revenue (millions of 2019 dollars)	469	1,227	1,976	3,836	8,999	16,535
Employment (total jobs)	18,804	23,488	20,688	38,953	110,231	202,305
Renewable						
Gross State Product (millions of 2019 dollars)	4,196	11,707	19,989	41,359	97,290	170,018
Personal Income (millions of 2019 dollars)	4,556	11,806	19,172	37,246	87,368	160,523
State & Local Tax Revenue (millions of 2019 dollars)	469	1,216	1,975	3,836	8,999	16,534
Employment (total jobs)	18,800	22,064	20,696	39,073	110,223	202,224

Note: All Market case under the No Carbon Price scenario is assumed to be the REMI Baseline scenario; employment values include full time and part time jobs.
Source: REMI; NERA calculations as explained in text.

Figure NERA–28 compares the REMI results under the Mid CO_2 Price scenario for each case, relative to the Low Carbon case. Results are very similar to those for the No Carbon Price scenario. The Low Carbon case and the Renewable case have virtually the same economic impacts. In contrast, the growth in the Nevada economy would be noticeably greater under the Development case in one year (2021) and noticeably smaller under the All Market case under the majority of the years (on the order of 2,000 to 3,000 jobs).

FIGURE NERA - 28. MID CO_2 PRICE SCENARIO NEVADA ECONOMIC IMPACTS FOR THE PRIMARY CASES COMPARED TO LOW CARBON CASE

	Nevada Economic Impacts Compared to 2018					
	2019	**2021**	**2023**	**2028**	**2038**	**2048**
Low Carbon						
Gross State Product (millions of 2019 dollars)	-	-	-	-	-	-
Personal Income (millions of 2019 dollars)	-	-	-	-	-	-
State & Local Tax Revenue (millions of 2019 dollars)	-	-	-	-	-	-
Employment (total jobs)	-	-	-	-	-	-
All Market						
Gross State Product (millions of 2019 dollars)	0	-306	-371	307	-19	-296
Personal Income (millions of 2019 dollars)	0	-203	-257	180	-21	-190
State & Local Tax Revenue (millions of 2019 dollars)	0	-21	-26	19	-2	-20
Employment (total jobs)	0	-3,081	-2,837	2,503	-151	-1,781
Development						
Gross State Product (millions of 2019 dollars)	1	161	9	-10	-1	7
Personal Income (millions of 2019 dollars)	0	106	12	-4	1	10
State & Local Tax Revenue (millions of 2019 dollars)	0	11	1	0	0	1
Employment (total jobs)	4	1,424	-27	-113	3	77
Renewable						
Gross State Product (millions of 2019 dollars)	0	0	-5	2	-1	-1
Personal Income (millions of 2019 dollars)	0	0	-2	1	-1	-1
State & Local Tax Revenue (millions of 2019 dollars)	0	0	0	0	0	0
Employment (total jobs)	0	0	-19	7	-5	-4

Note: This table compares output relative to the Low Carbon case under the Mid CO2 Price scenario; the All Market case under the No Carbon Price scenario is assumed to be the REMI Baseline scenario; expenditure and electricity revenue inputs for the other three cases are in comparison to the All Market case under the No Carbon Price scenario; employment values include full time and part time jobs.
Source: REMI; NERA calculations as explained in text.

The following tables provide the equivalent inputs and results for the Q3 Alternative case, based upon the assumption that the Question 3 is approved by voters and implemented in 2023 (and thus results are only presented for 2019 through 2023). As noted, these estimates are not comparable to those for the other four cases. Figure NERA–29 shows the average annual relevant expenditures for the economic impacts analysis for the Q3 Alternative over the period from 2019 to 2023.

FIGURE NERA – 29. AVERAGE ANNUAL RELEVANT EXPENDITURES FOR Q3 ALTERNATIVE (2019$ MILLIONS), 2019-2048

	Q3
Construction	$290
Fuel	$633
O&M	$221
Total	$1,144

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–30 shows the average annual Companies' projected electricity revenue from 2019 to 2023 apportioned by customer class for the Q3 Alternative case.

FIGURE NERA - 30. AVERAGE ANNUAL ELECTRICITY REVENUE REQUIREMENTS BY CUSTOMER CLASS FOR Q3 ALTERNATIVE (2019$ MILLIONS), 2019-2048

	Q3
Total	**$1,263**
Residential	$530
Commercial	$327
Industrial	$406

Note: All values are average annual values over the period from 2019 to 2048 in millions of 2019 dollars.

Figure NERA–31 provides economic impact results for the Q3 Alternative case, which assumes a Mid CO_2 Price scenario. As noted, these estimates are not comparable to those for the other four cases.

FIGURE NERA - 31. Q3 SCENARIO NEVADA ECONOMIC IMPACTS

	Nevada Economic Impacts Compared to 2018				
	2019	2020	2021	2022	2023
Q3					
Gross State Product (millions of 2019 dollars)	4,196	7,505	11,119	15,848	19,663
Personal Income (millions of 2019 dollars)	4,556	7,851	11,417	15,958	18,939
State & Local Tax Revenue (millions of 2019 dollars)	469	809	1,176	1,644	1,951
Employment (total jobs)	18,800	16,155	16,146	19,513	18,060

Note: All Market case under the No Carbon Price scenario is assumed to be the REMI Baseline scenario; employment values include full time and part time jobs.
Source: REMI; NERA calculations as explained in text.

All values for the Q3 Alternative are based on the Mid CO_2 Price scenario only. Since the Mid CO_2 Price scenario assumes a binding cap in 2025, and the analysis period for the Q3 Alternative ends in 2023, using the No Carbon Price scenario as an alternative would have no effect on the results.

I. LONG TERM AVOIDED COSTS

Per NAC § 704.9492, the Company has computed long-term avoided costs ("LTAC") based on the Preferred Plan for purposes of determining LTAC rates. Under Nevada's implementation of the Public Utility Regulatory Policies Act ("PURPA"), the Companies' LTACs are calculated based on the mix of resources approved by the Commission through the integrated resource planning process. LTAC rates calculated based on the Companies approved IRP are to be offered to qualifying facilities ("QFs") for blocks of capacity approved in the IRP. Estimates of LTACs are first filed in the utility's IRP, based on the utility's Preferred Plan. Here, the Companies have calculated estimated LTAC using two methods: Uncapped Long-Term Avoided Costs and Capped Long-Term Avoided Costs. The methodology for both is outlined below. The use of a capped methodology is consistent with the purpose of the LTAC calculation: to reflect utility's next best alternative for serving the next demanded MW of capacity and energy.

Uncapped Long-Term Avoided Costs:

1. Determine the hourly marginal energy costs from the Preferred Plan.
2. Using the forecasted capacity cost described in the Load Forecast and Market Fundamentals volume, convert the forecasted capacity cost from $/kW-mo. to $/MWh based on a 7x16 hours on-peak period for the months of July, August, and September.
3. Add the converted capacity costs in $/MWh to the marginal energy costs for the sixteen peak hours for every day of the month.
4. Average all of the hours in the month to determine the average monthly Uncapped Long-Term Avoided Cost for each month of each year.

Capped Long-Term Avoided Costs:

1. Determine the hourly marginal energy costs from the Preferred Plan.
2. Using the forecasted capacity cost described in the Load Forecast and Market Fundamentals volume, convert the forecasted capacity cost from $/kW-mo. to $/MWh based on a 7x16 hours on-peak period for the months of July, August, and September.
3. Add the converted capacity costs in $/MWh to the marginal energy costs for the sixteen peak hours for every day of the month.
4. Compare the hourly marginal energy costs with the added capacity to the supply curve and pricing of the least cost bid for 50 MW of renewable resource received in response to the 2018 Renewable RFP.
5. If the supply curve shows that the resource will generate for a given hour and the all-in pricing (energy and capacity) of that resource is less than the marginal energy cost with capacity for that hour, select the price of the new resource as the appropriate proxy for the long-term avoided cost for that hour.
6. Average all of the hours in the month to determine the average monthly long-term avoided cost for each month of each year.

Figures EA-16 and EA-17 show the average monthly uncapped long-term avoided costs for each Company.

FIGURE EA-16
SIERRA UNCAPPED LONG-TERM AVOIDED COSTS

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2019	$ 21.84	$ 20.20	$ 17.62	$ 14.30	$ 15.33	$ 18.52	$ 51.69	$ 50.90	$ 47.35	$ 16.86	$ 18.86	$ 21.02
2020	$ 19.72	$ 20.72	$ 18.39	$ 16.16	$ 19.32	$ 20.08	$ 54.55	$ 53.03	$ 49.13	$ 15.86	$ 19.42	$ 23.76
2021	$ 21.76	$ 22.24	$ 20.66	$ 17.58	$ 18.69	$ 22.66	$ 58.37	$ 57.78	$ 54.01	$ 19.25	$ 20.90	$ 23.34
2022	$ 22.90	$ 20.19	$ 16.83	$ 14.91	$ 18.39	$ 24.55	$ 61.36	$ 60.43	$ 58.98	$ 28.40	$ 23.68	$ 22.91
2023	$ 23.33	$ 23.11	$ 20.72	$ 17.42	$ 20.39	$ 24.95	$ 64.49	$ 63.87	$ 60.06	$ 27.70	$ 26.73	$ 26.34
2024	$ 26.22	$ 23.82	$ 18.07	$ 16.98	$ 20.82	$ 26.12	$ 67.26	$ 67.30	$ 62.99	$ 29.46	$ 27.54	$ 30.07
2025	$ 32.16	$ 34.07	$ 25.79	$ 23.73	$ 27.15	$ 33.86	$ 75.13	$ 73.55	$ 68.92	$ 36.10	$ 32.07	$ 33.21
2026	$ 34.43	$ 34.31	$ 27.85	$ 27.88	$ 30.79	$ 36.53	$ 77.82	$ 76.23	$ 71.91	$ 33.50	$ 34.46	$ 36.10
2027	$ 38.11	$ 35.29	$ 32.05	$ 30.42	$ 31.60	$ 38.29	$ 81.34	$ 80.59	$ 75.18	$ 36.27	$ 37.38	$ 39.58
2028	$ 38.66	$ 40.19	$ 31.48	$ 27.55	$ 34.43	$ 41.44	$ 86.51	$ 86.22	$ 81.25	$ 41.76	$ 41.70	$ 46.31
2029	$ 42.69	$ 42.23	$ 32.92	$ 29.59	$ 36.13	$ 43.86	$ 89.20	$ 89.42	$ 82.21	$ 42.40	$ 42.88	$ 44.69
2030	$ 42.75	$ 43.21	$ 34.82	$ 33.09	$ 37.73	$ 45.44	$ 95.27	$ 94.26	$ 88.14	$ 48.36	$ 48.80	$ 49.78
2031	$ 46.69	$ 46.63	$ 34.23	$ 31.20	$ 39.37	$ 46.44	$ 98.13	$ 98.51	$ 89.72	$ 46.48	$ 49.38	$ 49.95
2032	$ 44.32	$ 38.84	$ 35.68	$ 35.17	$ 38.16	$ 43.64	$ 100.61	$ 99.30	$ 90.22	$ 40.52	$ 47.07	$ 54.08
2033	$ 43.77	$ 38.14	$ 38.32	$ 36.08	$ 38.78	$ 46.99	$ 106.76	$ 107.44	$ 93.55	$ 42.86	$ 47.19	$ 57.08
2034	$ 47.87	$ 41.31	$ 39.71	$ 37.45	$ 40.11	$ 47.99	$ 109.17	$ 109.97	$ 96.36	$ 43.29	$ 48.73	$ 54.46
2035	$ 52.40	$ 49.88	$ 39.75	$ 38.80	$ 40.35	$ 49.84	$ 111.99	$ 108.88	$ 96.80	$ 46.63	$ 49.92	$ 56.81
2036	$ 54.80	$ 44.37	$ 40.93	$ 38.15	$ 43.07	$ 53.00	$ 115.64	$ 112.49	$ 101.68	$ 46.57	$ 51.88	$ 59.96
2037	$ 58.93	$ 51.17	$ 42.55	$ 40.91	$ 44.32	$ 56.17	$ 121.01	$ 116.79	$ 104.63	$ 50.94	$ 53.56	$ 60.20
2038	$ 62.06	$ 57.30	$ 47.22	$ 45.86	$ 48.62	$ 61.17	$ 125.58	$ 121.95	$ 110.31	$ 55.96	$ 58.95	$ 64.12
2039	$ 63.63	$ 58.06	$ 47.89	$ 46.98	$ 49.87	$ 61.34	$ 127.02	$ 124.92	$ 112.12	$ 54.92	$ 61.41	$ 67.46
2040	$ 69.84	$ 65.00	$ 51.38	$ 51.71	$ 58.88	$ 63.81	$ 127.82	$ 128.47	$ 115.57	$ 57.97	$ 65.46	$ 69.07
2041	$ 69.96	$ 68.87	$ 55.95	$ 56.53	$ 58.18	$ 68.32	$ 134.58	$ 131.45	$ 120.08	$ 63.22	$ 68.56	$ 72.10
2042	$ 74.22	$ 74.27	$ 52.38	$ 47.67	$ 58.21	$ 74.87	$ 142.78	$ 137.64	$ 122.47	$ 63.94	$ 71.71	$ 73.80
2043	$ 73.91	$ 75.40	$ 52.52	$ 48.76	$ 59.71	$ 77.96	$ 151.49	$ 143.28	$ 127.62	$ 66.48	$ 70.96	$ 76.39
2044	$ 87.55	$ 69.88	$ 55.18	$ 56.73	$ 59.56	$ 74.90	$ 144.86	$ 147.54	$ 129.57	$ 64.94	$ 72.75	$ 76.92
2045	$ 80.27	$ 77.86	$ 60.18	$ 51.99	$ 62.42	$ 77.63	$ 154.44	$ 153.17	$ 133.91	$ 68.06	$ 78.03	$ 81.35
2046	$ 83.68	$ 82.56	$ 64.00	$ 58.60	$ 65.88	$ 84.59	$ 164.44	$ 157.18	$ 138.62	$ 76.12	$ 80.39	$ 85.94
2047	$ 73.60	$ 75.23	$ 54.39	$ 52.71	$ 61.73	$ 85.33	$ 151.22	$ 146.88	$ 132.90	$ 66.52	$ 63.70	$ 69.95
2048	$ 70.79	$ 70.74	$ 57.74	$ 55.48	$ 58.36	$ 78.03	$ 151.82	$ 160.45	$ 133.29	$ 66.74	$ 66.08	$ 71.04

FIGURE EA-17
NEVADA POWER UNCAPPED LONG-TERM AVOIDED COSTS

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2019	$ 21.84	$ 20.20	$ 17.62	$ 14.20	$ 15.33	$ 18.46	$ 51.69	$ 50.90	$ 47.21	$ 15.64	$ 18.86	$ 21.02
2020	$ 19.72	$ 20.72	$ 18.34	$ 16.16	$ 19.32	$ 20.08	$ 54.56	$ 53.03	$ 49.13	$ 15.86	$ 18.81	$ 23.49
2021	$ 21.76	$ 22.24	$ 20.66	$ 17.58	$ 18.67	$ 22.65	$ 58.37	$ 57.78	$ 54.01	$ 19.25	$ 20.90	$ 23.10
2022	$ 22.90	$ 19.99	$ 16.83	$ 14.77	$ 18.38	$ 24.55	$ 61.36	$ 60.43	$ 58.99	$ 25.39	$ 23.68	$ 22.91
2023	$ 23.33	$ 23.11	$ 20.68	$ 17.42	$ 20.39	$ 24.95	$ 64.49	$ 63.68	$ 60.06	$ 24.76	$ 26.72	$ 26.34
2024	$ 26.20	$ 23.82	$ 18.08	$ 16.98	$ 20.82	$ 26.12	$ 67.26	$ 67.37	$ 62.99	$ 29.46	$ 27.53	$ 30.07
2025	$ 32.12	$ 34.07	$ 25.79	$ 23.73	$ 27.15	$ 33.82	$ 75.13	$ 73.47	$ 68.92	$ 36.10	$ 32.07	$ 33.21
2026	$ 34.43	$ 34.31	$ 27.85	$ 27.88	$ 30.79	$ 36.43	$ 77.82	$ 76.20	$ 71.93	$ 33.12	$ 34.46	$ 35.98
2027	$ 37.78	$ 35.29	$ 32.05	$ 30.42	$ 31.60	$ 38.31	$ 81.35	$ 80.59	$ 75.18	$ 34.92	$ 37.38	$ 39.58
2028	$ 38.66	$ 40.19	$ 31.48	$ 27.55	$ 34.43	$ 41.45	$ 86.52	$ 86.25	$ 81.25	$ 38.60	$ 41.70	$ 46.32
2029	$ 42.69	$ 42.23	$ 32.92	$ 29.59	$ 36.13	$ 44.18	$ 89.45	$ 89.79	$ 82.32	$ 42.40	$ 42.88	$ 44.69
2030	$ 42.75	$ 43.21	$ 34.82	$ 33.09	$ 37.74	$ 45.49	$ 95.35	$ 94.31	$ 88.15	$ 48.36	$ 48.80	$ 49.78
2031	$ 46.69	$ 46.63	$ 34.23	$ 31.20	$ 39.38	$ 46.50	$ 98.17	$ 98.62	$ 89.76	$ 46.50	$ 49.38	$ 49.95
2032	$ 44.31	$ 38.84	$ 35.68	$ 35.19	$ 38.17	$ 45.69	$ 102.25	$ 100.40	$ 90.89	$ 40.53	$ 47.07	$ 54.08
2033	$ 43.09	$ 38.14	$ 38.33	$ 36.15	$ 39.10	$ 48.07	$ 107.66	$ 108.24	$ 93.99	$ 42.90	$ 47.19	$ 57.08
2034	$ 47.87	$ 41.31	$ 39.72	$ 37.50	$ 40.68	$ 49.31	$ 110.02	$ 110.48	$ 96.79	$ 43.34	$ 48.73	$ 54.39
2035	$ 52.40	$ 49.88	$ 39.77	$ 38.93	$ 40.46	$ 50.69	$ 111.51	$ 109.30	$ 97.39	$ 46.63	$ 49.92	$ 56.78
2036	$ 54.80	$ 44.37	$ 40.95	$ 38.31	$ 43.13	$ 53.22	$ 115.75	$ 112.54	$ 101.70	$ 46.59	$ 51.87	$ 59.93
2037	$ 58.85	$ 51.17	$ 42.58	$ 41.06	$ 44.70	$ 56.30	$ 121.19	$ 116.85	$ 104.66	$ 50.98	$ 53.53	$ 60.13
2038	$ 62.06	$ 57.28	$ 47.24	$ 45.99	$ 48.85	$ 61.24	$ 126.04	$ 122.09	$ 110.38	$ 55.99	$ 58.91	$ 64.04
2039	$ 63.63	$ 58.06	$ 47.90	$ 47.19	$ 50.07	$ 61.45	$ 127.30	$ 125.12	$ 112.21	$ 55.00	$ 61.38	$ 67.43
2040	$ 69.84	$ 65.00	$ 51.40	$ 52.09	$ 59.47	$ 63.94	$ 127.94	$ 128.60	$ 115.68	$ 58.04	$ 65.06	$ 68.57
2041	$ 68.83	$ 68.58	$ 55.87	$ 56.53	$ 58.33	$ 68.59	$ 134.74	$ 131.63	$ 120.09	$ 63.22	$ 68.51	$ 71.86
2042	$ 74.00	$ 74.27	$ 52.37	$ 47.68	$ 58.26	$ 75.08	$ 142.96	$ 137.84	$ 122.53	$ 63.61	$ 69.76	$ 73.25
2043	$ 73.70	$ 75.39	$ 52.40	$ 48.72	$ 59.73	$ 78.16	$ 151.87	$ 143.60	$ 127.69	$ 66.33	$ 70.38	$ 75.90
2044	$ 73.95	$ 69.88	$ 54.85	$ 52.98	$ 59.56	$ 77.99	$ 150.16	$ 147.09	$ 131.65	$ 66.07	$ 72.76	$ 76.80
2045	$ 79.78	$ 77.90	$ 60.71	$ 53.95	$ 63.78	$ 81.80	$ 160.37	$ 153.35	$ 135.75	$ 70.30	$ 78.03	$ 81.05
2046	$ 83.66	$ 82.57	$ 64.56	$ 60.72	$ 67.20	$ 89.88	$ 169.27	$ 162.72	$ 140.27	$ 77.62	$ 80.40	$ 85.81
2047	$ 73.64	$ 76.13	$ 54.39	$ 53.01	$ 64.49	$ 79.67	$ 156.45	$ 149.88	$ 134.87	$ 66.60	$ 63.70	$ 69.95
2048	$ 71.05	$ 71.17	$ 57.74	$ 55.57	$ 59.50	$ 81.45	$ 160.48	$ 156.84	$ 135.43	$ 67.18	$ 66.08	$ 70.83

Figures EA-18 and EA-19 show the average monthly capped long-term avoided costs for each Company.

FIGURE EA-18
SIERRA CAPPED LONG-TERM AVOIDED COSTS

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2019	$ 21.84	$ 20.20	$ 17.62	$ 14.30	$ 15.33	$ 18.52	$ 51.69	$ 50.90	$ 47.35	$ 16.86	$ 18.86	$ 21.02
2020	$ 19.72	$ 20.72	$ 18.39	$ 16.16	$ 19.32	$ 20.08	$ 54.55	$ 53.03	$ 49.13	$ 15.86	$ 19.42	$ 23.76
2021	$ 21.72	$ 22.24	$ 20.64	$ 17.58	$ 18.68	$ 22.40	$ 34.61	$ 36.62	$ 34.88	$ 19.24	$ 20.90	$ 23.34
2022	$ 22.90	$ 20.19	$ 16.83	$ 14.91	$ 18.39	$ 23.96	$ 36.46	$ 38.37	$ 38.07	$ 28.35	$ 23.67	$ 22.91
2023	$ 23.33	$ 23.10	$ 20.66	$ 17.41	$ 20.38	$ 24.45	$ 37.29	$ 39.73	$ 37.84	$ 27.54	$ 26.66	$ 26.34
2024	$ 26.12	$ 23.82	$ 18.07	$ 16.98	$ 20.78	$ 25.53	$ 38.22	$ 41.08	$ 39.15	$ 29.17	$ 27.51	$ 29.98
2025	$ 31.95	$ 33.93	$ 25.58	$ 23.62	$ 26.88	$ 31.42	$ 41.97	$ 44.43	$ 42.53	$ 35.14	$ 31.76	$ 32.88
2026	$ 33.54	$ 33.72	$ 27.25	$ 27.40	$ 30.11	$ 33.12	$ 43.09	$ 45.81	$ 44.10	$ 32.29	$ 33.33	$ 34.78
2027	$ 36.17	$ 34.01	$ 30.86	$ 29.53	$ 30.48	$ 33.94	$ 44.53	$ 47.68	$ 45.74	$ 34.38	$ 35.39	$ 37.52
2028	$ 36.16	$ 37.81	$ 30.08	$ 26.63	$ 32.24	$ 35.41	$ 46.32	$ 49.84	$ 48.46	$ 38.58	$ 38.67	$ 42.85
2029	$ 38.91	$ 39.04	$ 30.96	$ 28.09	$ 32.95	$ 36.57	$ 47.24	$ 51.37	$ 48.37	$ 38.23	$ 38.93	$ 40.98
2030	$ 38.36	$ 39.24	$ 31.97	$ 30.37	$ 33.87	$ 37.45	$ 49.55	$ 53.53	$ 51.26	$ 42.34	$ 43.13	$ 44.59
2031	$ 41.25	$ 42.22	$ 31.33	$ 28.68	$ 34.61	$ 37.67	$ 51.02	$ 56.00	$ 53.53	$ 40.99	$ 43.67	$ 43.95
2032	$ 39.53	$ 36.07	$ 32.51	$ 31.69	$ 33.85	$ 35.18	$ 52.39	$ 57.20	$ 54.69	$ 36.34	$ 40.99	$ 46.68
2033	$ 39.06	$ 35.32	$ 34.40	$ 32.19	$ 34.21	$ 37.14	$ 55.31	$ 60.98	$ 57.64	$ 38.59	$ 41.62	$ 49.84
2034	$ 42.43	$ 37.84	$ 35.48	$ 33.18	$ 35.07	$ 37.57	$ 56.11	$ 62.08	$ 58.91	$ 39.30	$ 42.76	$ 46.89
2035	$ 44.58	$ 44.35	$ 35.50	$ 34.10	$ 35.06	$ 38.61	$ 57.52	$ 61.55	$ 59.27	$ 41.91	$ 43.28	$ 48.02
2036	$ 45.73	$ 40.00	$ 36.31	$ 33.60	$ 36.73	$ 40.77	$ 58.16	$ 63.15	$ 61.42	$ 41.46	$ 44.00	$ 50.65
2037	$ 49.24	$ 44.76	$ 37.33	$ 35.45	$ 37.67	$ 41.85	$ 59.94	$ 64.73	$ 62.47	$ 44.57	$ 45.44	$ 50.81
2038	$ 50.20	$ 48.23	$ 40.06	$ 38.43	$ 40.14	$ 44.33	$ 61.91	$ 66.72	$ 64.27	$ 47.70	$ 48.70	$ 53.01
2039	$ 51.36	$ 48.59	$ 40.51	$ 39.21	$ 40.76	$ 44.52	$ 62.10	$ 67.67	$ 65.13	$ 46.85	$ 49.94	$ 55.38
2040	$ 55.25	$ 52.35	$ 42.42	$ 41.96	$ 46.12	$ 46.19	$ 62.90	$ 69.90	$ 65.77	$ 48.89	$ 51.80	$ 55.70
2041	$ 54.55	$ 54.04	$ 45.09	$ 43.53	$ 44.83	$ 48.58	$ 65.15	$ 70.66	$ 67.53	$ 51.24	$ 53.72	$ 57.85
2042	$ 59.39	$ 58.50	$ 44.11	$ 40.29	$ 46.96	$ 52.32	$ 69.17	$ 74.26	$ 71.32	$ 53.53	$ 56.68	$ 59.51
2043	$ 59.14	$ 59.41	$ 44.68	$ 41.20	$ 47.27	$ 53.79	$ 73.08	$ 77.35	$ 72.38	$ 54.83	$ 57.19	$ 60.79
2044	$ 74.41	$ 60.03	$ 48.64	$ 49.26	$ 48.66	$ 52.82	$ 71.53	$ 81.79	$ 76.58	$ 57.10	$ 58.83	$ 63.71
2045	$ 63.59	$ 63.43	$ 50.33	$ 45.13	$ 49.74	$ 54.29	$ 75.64	$ 84.31	$ 78.17	$ 59.12	$ 60.83	$ 65.89
2046	$ 83.68	$ 82.56	$ 64.00	$ 58.60	$ 65.88	$ 84.59	$ 164.44	$ 157.18	$ 138.62	$ 76.12	$ 80.39	$ 85.94
2047	$ 73.60	$ 75.23	$ 54.39	$ 52.71	$ 61.73	$ 85.33	$ 151.22	$ 146.88	$ 132.90	$ 66.52	$ 63.70	$ 69.95
2048	$ 70.79	$ 70.74	$ 57.74	$ 55.48	$ 58.36	$ 78.03	$ 151.82	$ 160.45	$ 133.29	$ 66.74	$ 66.08	$ 68.73

FIGURE EA-19
NEVADA POWER CAPPED LONG-TERM AVOIDED COSTS

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2019	$ 21.84	$ 20.20	$ 17.62	$ 14.20	$ 15.33	$ 18.46	$ 51.69	$ 50.90	$ 47.21	$ 15.64	$ 18.86	$ 21.02
2020	$ 19.72	$ 20.72	$ 18.34	$ 16.16	$ 19.32	$ 20.08	$ 54.56	$ 53.03	$ 49.13	$ 15.86	$ 18.81	$ 23.49
2021	$ 21.72	$ 22.24	$ 20.64	$ 17.58	$ 18.66	$ 22.39	$ 34.61	$ 36.62	$ 34.88	$ 19.24	$ 20.90	$ 23.10
2022	$ 22.90	$ 19.99	$ 16.83	$ 14.77	$ 18.38	$ 23.96	$ 36.46	$ 38.37	$ 38.07	$ 25.36	$ 23.67	$ 22.91
2023	$ 23.33	$ 23.10	$ 20.63	$ 17.41	$ 20.38	$ 24.45	$ 37.29	$ 39.54	$ 37.84	$ 24.71	$ 26.66	$ 26.34
2024	$ 26.10	$ 23.82	$ 18.08	$ 16.98	$ 20.78	$ 25.53	$ 38.22	$ 41.08	$ 39.15	$ 29.17	$ 27.51	$ 29.98
2025	$ 31.91	$ 33.93	$ 25.58	$ 23.62	$ 26.88	$ 31.38	$ 41.97	$ 44.36	$ 42.53	$ 35.14	$ 31.76	$ 32.88
2026	$ 33.54	$ 33.72	$ 27.25	$ 27.40	$ 30.11	$ 33.03	$ 43.09	$ 45.79	$ 44.10	$ 31.99	$ 33.33	$ 34.66
2027	$ 35.89	$ 34.01	$ 30.85	$ 29.53	$ 30.48	$ 33.94	$ 44.53	$ 47.68	$ 45.74	$ 33.22	$ 35.39	$ 37.52
2028	$ 36.16	$ 37.81	$ 30.08	$ 26.63	$ 32.24	$ 35.41	$ 46.32	$ 49.84	$ 48.46	$ 35.68	$ 38.67	$ 42.85
2029	$ 38.91	$ 39.04	$ 30.96	$ 28.09	$ 32.95	$ 36.72	$ 47.25	$ 51.38	$ 48.38	$ 38.23	$ 38.93	$ 40.98
2030	$ 38.36	$ 39.24	$ 31.97	$ 30.37	$ 33.88	$ 37.48	$ 49.56	$ 53.54	$ 51.26	$ 42.34	$ 43.13	$ 44.59
2031	$ 41.25	$ 42.22	$ 31.33	$ 28.68	$ 34.62	$ 37.71	$ 51.03	$ 56.00	$ 53.53	$ 40.99	$ 43.67	$ 43.95
2032	$ 39.52	$ 36.07	$ 32.51	$ 31.70	$ 33.85	$ 36.47	$ 53.06	$ 57.65	$ 55.00	$ 36.34	$ 40.99	$ 46.68
2033	$ 38.44	$ 35.32	$ 34.40	$ 32.24	$ 34.51	$ 37.95	$ 55.66	$ 61.21	$ 57.79	$ 38.62	$ 41.62	$ 49.84
2034	$ 42.43	$ 37.84	$ 35.48	$ 33.21	$ 35.57	$ 38.58	$ 56.43	$ 62.26	$ 59.16	$ 39.33	$ 42.76	$ 46.83
2035	$ 44.58	$ 44.35	$ 35.52	$ 34.19	$ 35.16	$ 39.23	$ 56.64	$ 61.81	$ 59.64	$ 41.91	$ 43.28	$ 47.98
2036	$ 45.73	$ 40.00	$ 36.32	$ 33.75	$ 36.79	$ 40.94	$ 58.16	$ 63.15	$ 61.43	$ 41.46	$ 44.00	$ 50.63
2037	$ 49.17	$ 44.76	$ 37.36	$ 35.58	$ 38.04	$ 41.92	$ 60.00	$ 64.73	$ 62.47	$ 44.58	$ 45.40	$ 50.75
2038	$ 50.20	$ 48.21	$ 40.07	$ 38.51	$ 40.35	$ 44.31	$ 61.95	$ 66.72	$ 64.27	$ 47.70	$ 48.67	$ 52.93
2039	$ 51.36	$ 48.59	$ 40.51	$ 39.37	$ 40.92	$ 44.55	$ 62.10	$ 67.67	$ 65.13	$ 46.89	$ 49.91	$ 55.35
2040	$ 55.25	$ 52.35	$ 42.43	$ 42.27	$ 46.55	$ 46.20	$ 62.90	$ 69.90	$ 65.77	$ 48.89	$ 51.41	$ 55.25
2041	$ 53.56	$ 53.76	$ 45.02	$ 43.53	$ 44.86	$ 48.71	$ 65.15	$ 70.66	$ 67.53	$ 51.24	$ 53.67	$ 57.62
2042	$ 59.18	$ 58.50	$ 44.10	$ 40.29	$ 46.97	$ 52.34	$ 69.19	$ 74.26	$ 71.32	$ 53.21	$ 54.74	$ 59.03
2043	$ 58.93	$ 59.40	$ 44.58	$ 41.17	$ 47.28	$ 53.82	$ 73.07	$ 77.35	$ 72.38	$ 54.67	$ 56.62	$ 60.36
2044	$ 60.95	$ 60.03	$ 48.35	$ 45.51	$ 48.66	$ 54.09	$ 71.84	$ 78.50	$ 76.92	$ 58.02	$ 58.84	$ 63.59
2045	$ 63.10	$ 63.47	$ 50.75	$ 46.81	$ 50.65	$ 55.79	$ 75.97	$ 80.97	$ 78.66	$ 60.89	$ 60.83	$ 65.56
2046	$ 83.66	$ 82.57	$ 64.56	$ 60.72	$ 67.20	$ 89.88	$ 169.27	$ 162.72	$ 140.27	$ 77.62	$ 80.40	$ 85.81
2047	$ 73.64	$ 76.13	$ 54.39	$ 53.01	$ 64.49	$ 79.67	$ 156.45	$ 149.88	$ 134.87	$ 66.60	$ 63.70	$ 69.95
2048	$ 71.05	$ 71.17	$ 57.74	$ 55.57	$ 59.50	$ 81.45	$ 160.48	$ 156.84	$ 135.43	$ 67.18	$ 66.08	$ 68.52

The average monthly marginal costs are provided in Technical Appendix ECON-5. During the July - September period the capacity charge included in the market price forecast was added to the on peak hourly marginal energy cost to determine the LTAC.

Limits on Availability of Long-Term Avoided Cost Rate. The Companies propose that the LTAC rates be limited to a maximum of 50 MW of QF contracts and a 25-year term. In the event the Question 3 ballot initiative is passed in the November 2018 general election, then the Companies propose that the term of the QF contracts be limited to not extend beyond 2023.

Methodology to Derive Avoided Cost Payments. NAC § 704.9492 requires that in its triennial IRP filing, the utility must propose a methodology and calculate and file LTAC and preliminary LTAC rates that reflect the utility's Preferred Plan. These calculations are set forth above, and form the basis of a preliminary administratively determined LTAC and LTAC rates. The Companies' methodology includes a cap on the administratively determined LTAC rate based on bona fide market based responses to its most recent RFP.

Under NAC § 704.9496, The Commission must specifically address in its IRP order the utility's proposed estimated rates for LTAC, including the methodology and limits to be used going forward. Next, the regulation requires that within 60 days of the final determination in the utility's IRP, the utility must recalculate and refile LTAC that reflect the plan of action ultimately adopted by the Commission. NAC § 704.9496(2). Unless otherwise ordered by the Commission in its final determination regarding the utility's IRP, the recalculated rates reflecting LTAC also will reflect the same terms and be in the same format as the estimated rates originally filed by the utility in its IRP. NAC §704.9496(3).

The process contemplates that the recalculated administratively determined estimate of LTAC and LTAC rates, along with the limits proposed by the utility, may be disputed. NAC § 704.9496(4) provides that "if required," within 90 days of the filing of the recalculated estimated LTAC and LTAC rates, the Commission will hold a hearing to approve the administratively determined LTAC rates and the limits of capacity or energy or both that should be made available to be filled by QFs at the utility's LTAC. The Commission has 45 days after the hearing on the administratively determined estimate of LTAC and LTAC rates to issue an order on the matter. To distinguish this order from the order in the IRP, this order will be referred to below as the "Subsection 4" order.

Within 30 days of the issuance of the Subsection 4 order, the utility must solicit proposals to provide the utility capacity or energy or both, consistent with the Commission-approved methodology for estimating long-term avoided costs. NAC § 704.9496(5). Within 90 days of issuing this solicitation, the utility must file a report with the Commission summarizing the results of the solicitation. NAC § 704.9496(6).

Finally, NAC § 704.9496(7) provides that the utility's LTAC rate for each block of capacity authorized to be filled by QFs is the lower of the administratively determined estimate of the utility's LTAC and LTAC rate, or the competitive rate solicited.

SECTION 4. FINANCIAL PLAN

A. INTRODUCTION

The following section summarizes the results of the analysis of financial impacts of the Preferred and Alternative plans. The Financial Plan for both Nevada Power and Sierra spans a 20-year period (2019-2038) and analyzes these two scenarios from the perspective of several customer and company-financial impacts as mandated by NAC § 704.9401(1). Also included in the Financial Plan for both utilities are descriptions of the financial forecasting assumptions and common methodologies used to prepare the Financial Plans.

B. CAPITAL EXPENDITURES

The capital expenditures and cash flow analysis prepared for the Financial Plan utilize the CER model (described in the Economic Analysis section above) for the Preferred and Alternative plans. Figure FP-1 below compares Nevada Power's total capital expenditures (excluding AFUDC) for both plans on a yearly basis over the planning period. Capital expenditures for the 20-year period are estimated to total **$5.0 billion** for both the Preferred and Alternate plans. For Sierra, capital requirements shown in Figure FP-2 are estimated to total **$2.8 billion** for both the Preferred and Alternate plans. Additional project details can be found in the Economic Analysis section above.

FIGURE FP-1
NEVADA POWER
CAPITAL EXPENDITURES ($ - MILLIONS)
(Including AFUDC)

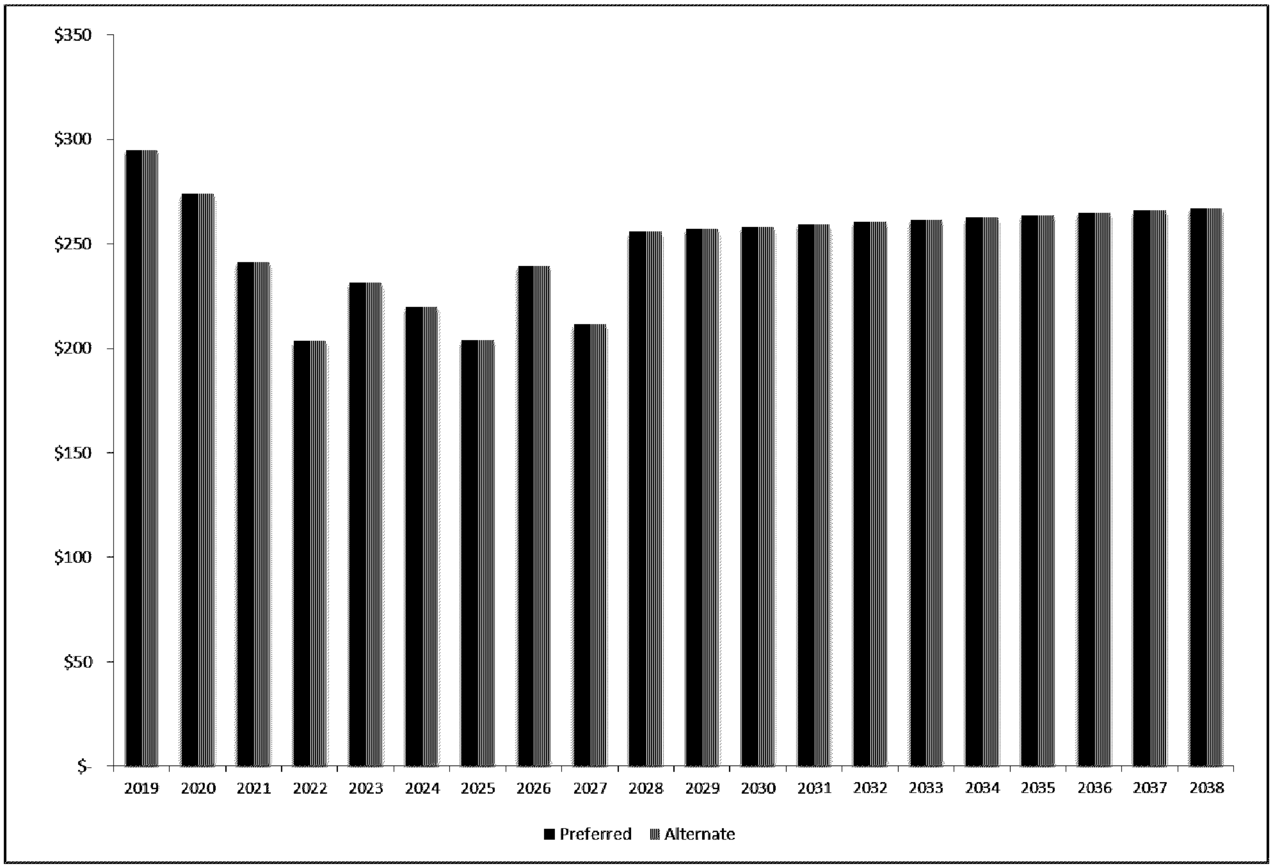
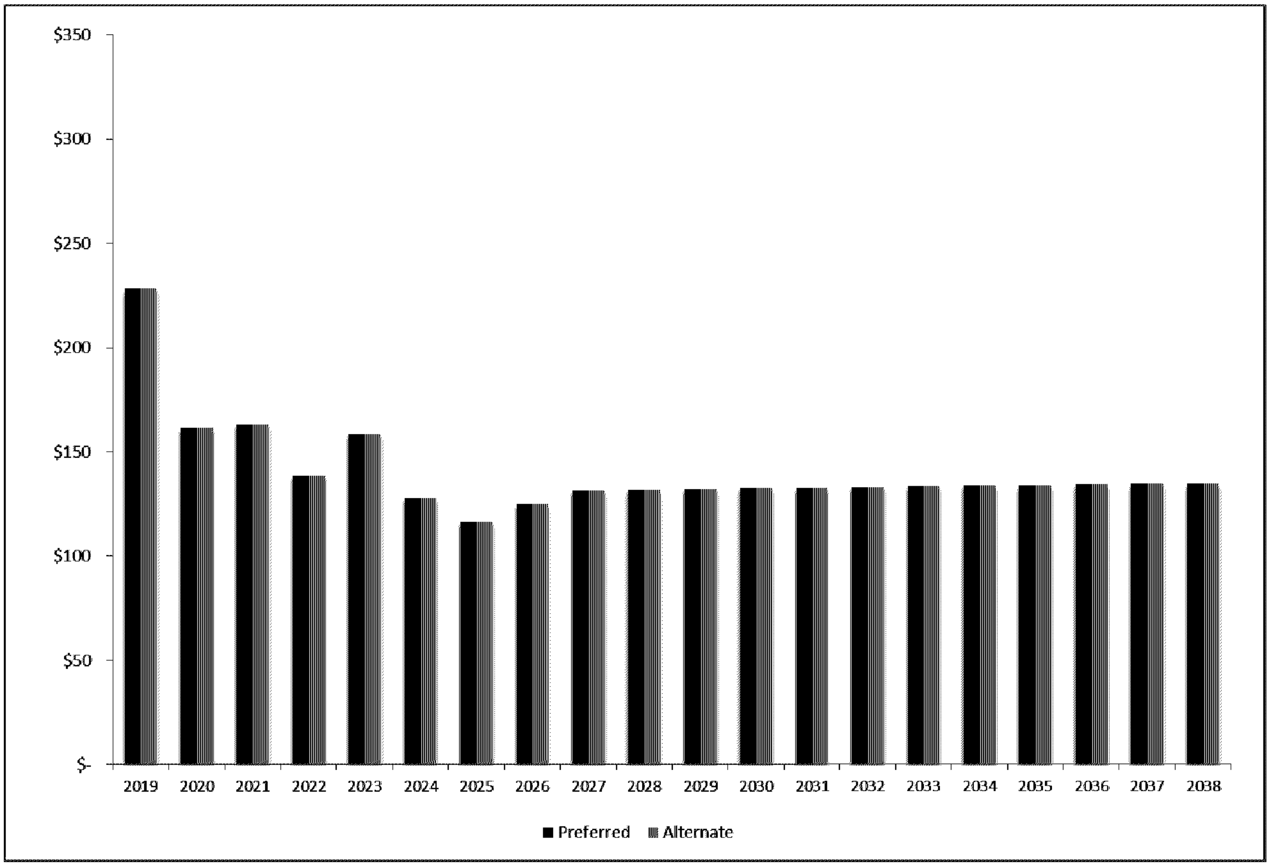


FIGURE FP-2
SIERRA
CAPITAL EXPENDITURES ($ - MILLIONS)
(Including AFUDC)



C. EXTERNAL FINANCING REQUIREMENTS (REDACTED)

For both utilities, cash generated from operations during the 2019 – 2038 period is in excess of the capital projects set forth in the CERs for each of the Preferred and Alternative plans. Nevertheless, the Companies will have a continued need to access external short and long-term financing in order to finance working capital, refinance maturing debt, and maintain capital structures that are appropriate for their investment grade credit ratings. For Nevada Power, Figure FP-3 depicts annual total external debt requirements over the forecast horizon for the Preferred and Alternate plans, respectively. External financing requirements for the 20-year period are estimated to total [redacted] for both the Preferred and Alternate plans. For Sierra, external debt financing projections are shown in Figure FP-4 and are estimated to total [redacted] for both plans.

FIGURE FP-3
NEVADA POWER - SUMMARY OF EXTERNAL DEBT FINANCING
($ - MILLIONS)

[redacted]

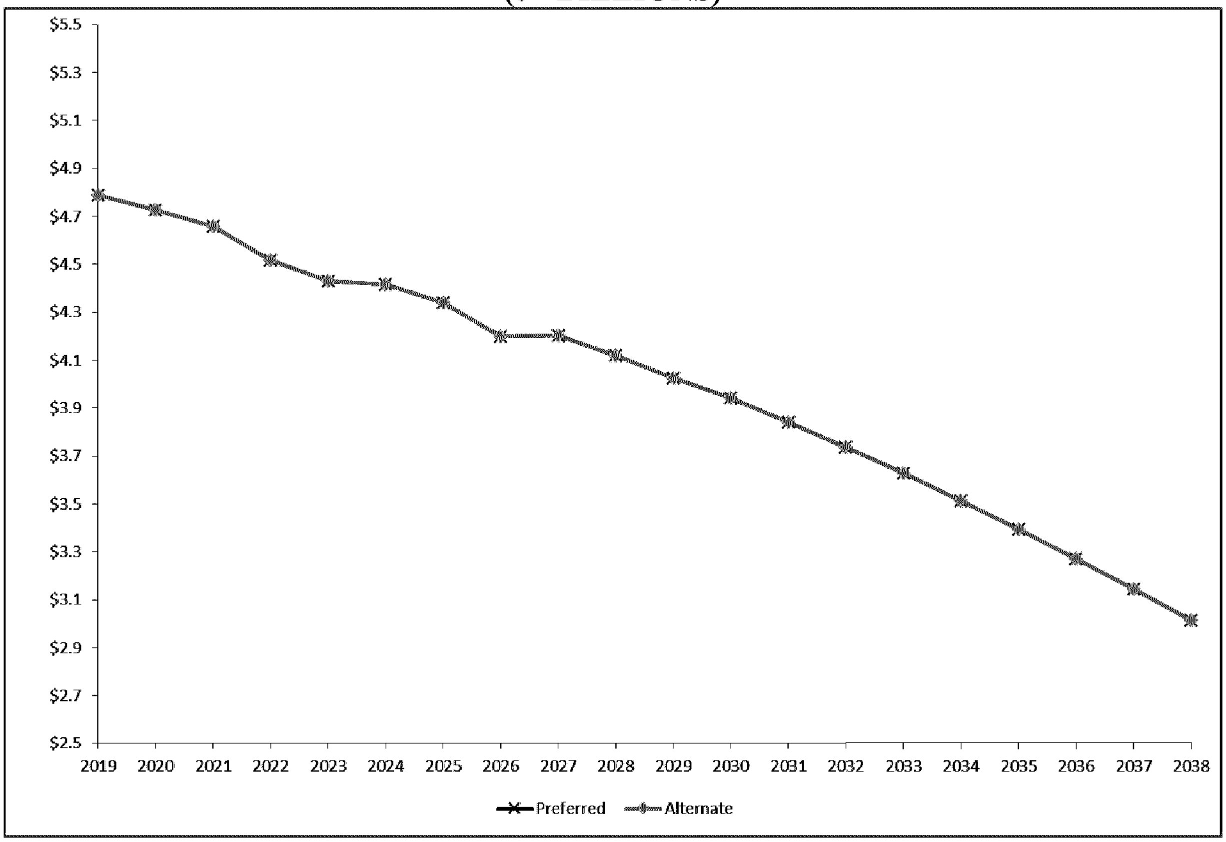
FIGURE FP-4
SIERRA - SUMMARY OF EXTERNAL DEBT FINANCING
($ - MILLIONS)

[redacted]

D. TOTAL RATE BASE

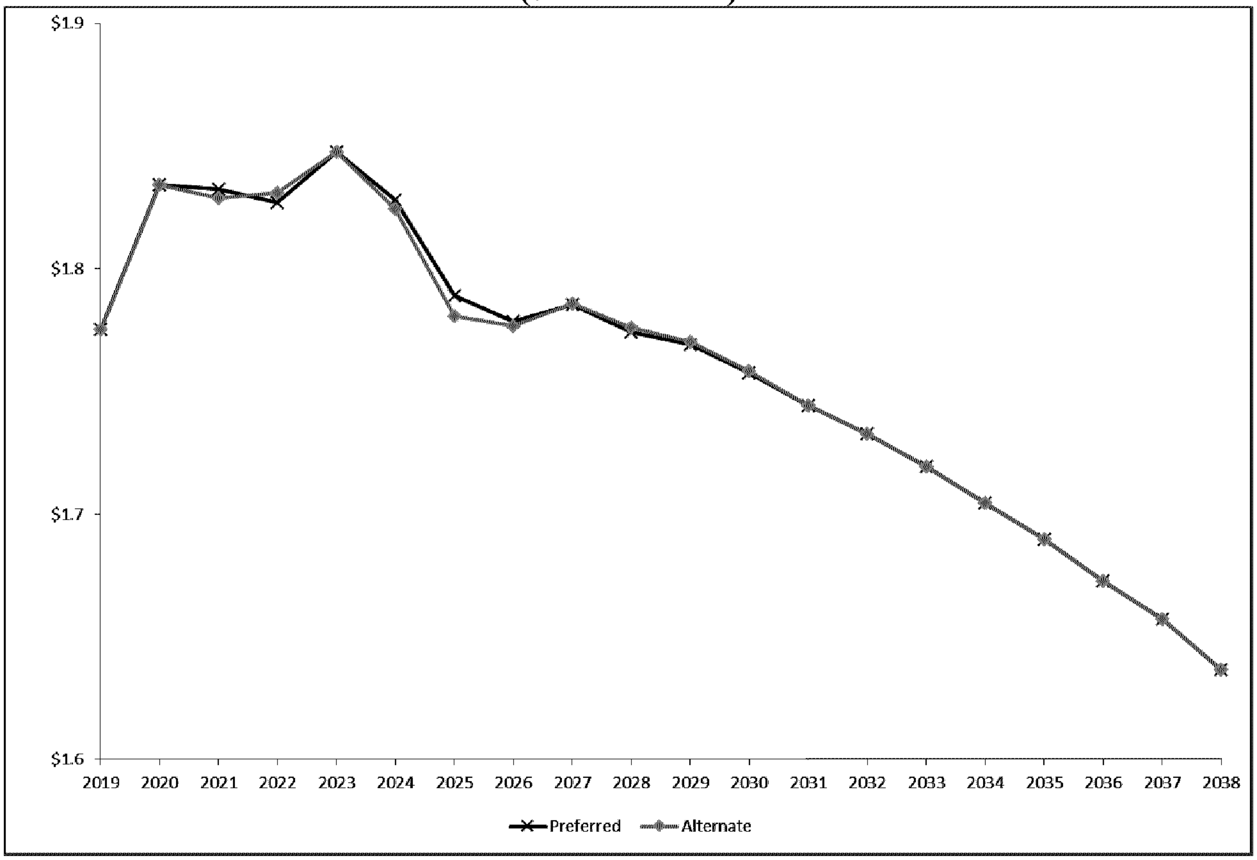
For Nevada Power, Figure FP-5 below compares total rate base per year over the planning period. Compound annual growth rates for rate base over the planning period total (2.29) percent for the Preferred Plan and (2.41) percent for the Alternative Plan.

FIGURE FP-5
NEVADA POWER
ELECTRIC RATE BASE
($ - BILLIONS)



For Sierra, Figure FP-6 below compares total rate base per year over the 20-year planning period. Compound annual growth rates for rate base over the planning period total (0.43) percent for the both plans.

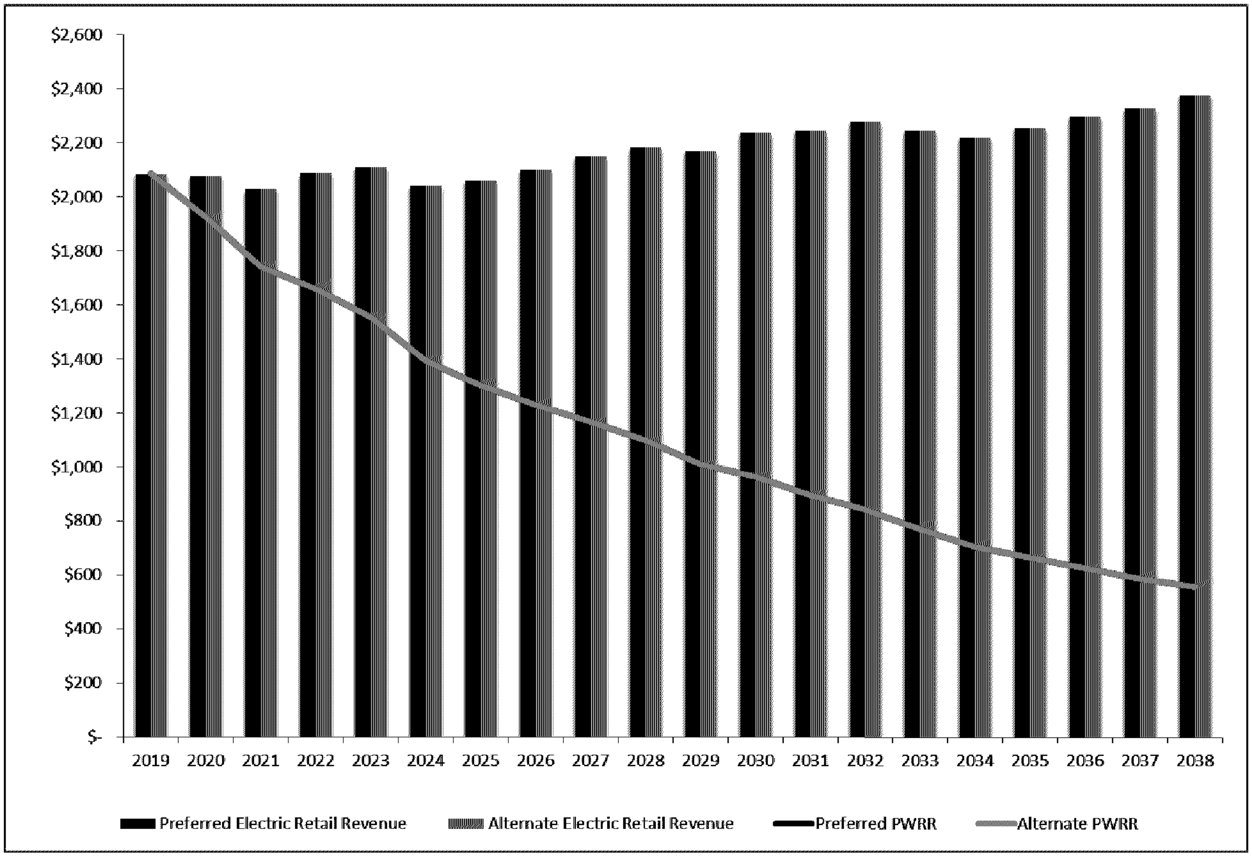
FIGURE FP-6
SIERRA
ELECTRIC RATE BASE
($ - BILLIONS)



E. ELECTRIC REVENUE

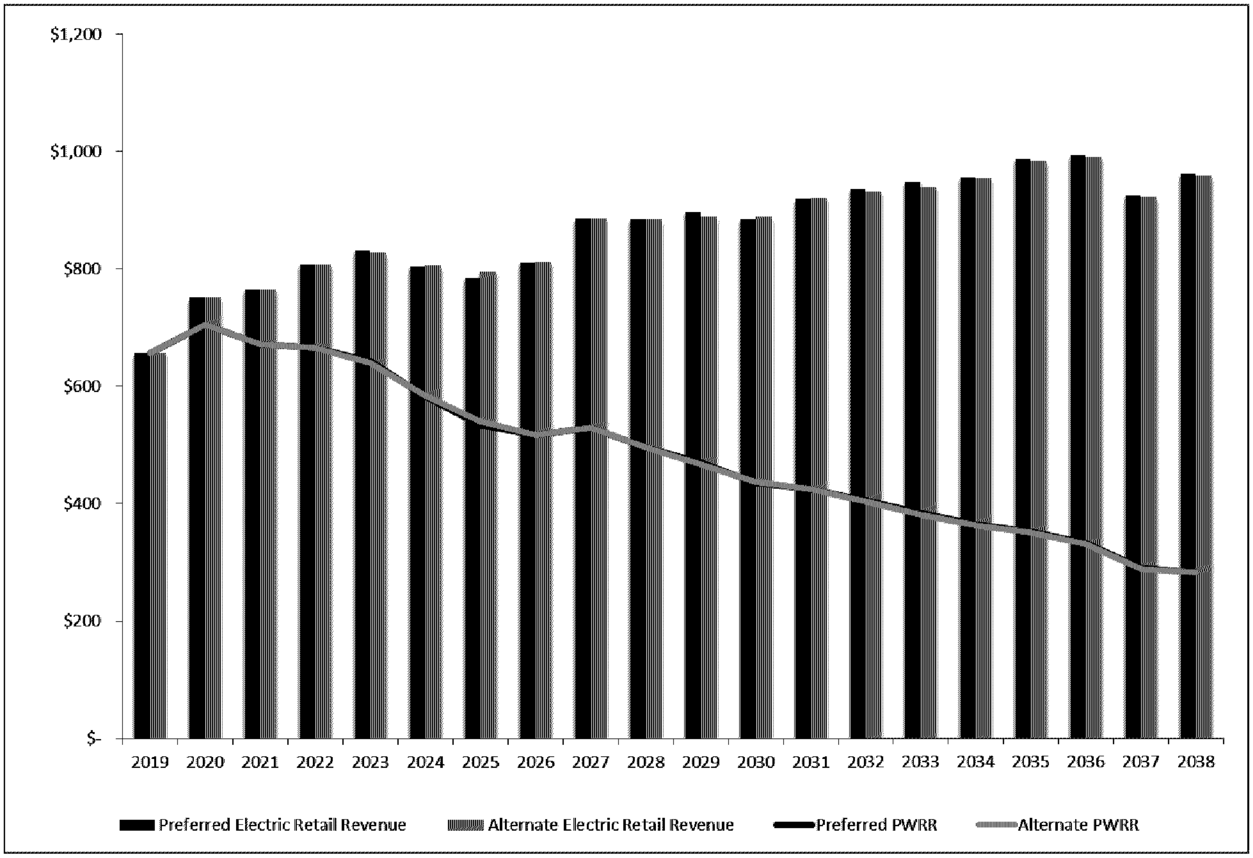
During the 20-year planning period, the Preferred and Alternative plans for Nevada Power result in a compound annual growth rate in electric retail revenue (including fuel costs) of 0.7 percent (from approximately $2.1 billion to $2.4 billion). Figure FP-7 shows estimated annual total electric revenue (in nominal and real dollars) for Nevada Power for the planning period as well as its present value.

FIGURE FP-7
NEVADA POWER
TOTAL RETAIL ELECTRIC REVENUES AND PRESENT WORTH
($ - MILLIONS)



For Sierra, the Preferred and Alternative plans result in a compound annual growth rate in electric retail revenue (including fuel costs) of 1.9 percent (from approximately $0.7 billion to $1.0 billion). Figure FP-8 shows estimated annual total electric revenue (in nominal and real dollars) for Sierra for the planning period as well as its present value.

FIGURE FP-8
SIERRA
TOTAL RETAIL ELECTRIC REVENUES AND PRESENT WORTH
($ - MILLIONS)



F. COMMON METHODOLOGIES / ASSUMPTIONS

The following section discusses the common methodologies and assumptions used in forecasting and evaluating the financial impact of the 2018 Joint IRP filing.

1. COMMON METHODOLOGIES

The financial analysis was performed using the Companies' financial forecasting model based on the Utilities International, Inc. platform. The model uses many of the same inputs (capital expenditures or "CAPEX," AFUDC rate based at the Companies' authorized rates of returns, production costs, depreciation rates and load forecast) from the CERs that are utilized in the economic analysis described earlier. Additional inputs include pro-forma capital structures and capital costs. The Utilities International, Inc. platform simulates general rate review proceedings on a timeline consistent with the schedule currently embodied in the Nevada Revised Statutes.

2. ASSUMPTIONS

Major financial modeling assumptions for Nevada Power are described below. Unless noted, assumptions are the same for the entire planning period.

- Nevada Power's next general rate increase/decrease will go into effect January 1, 2021.
- Inflation Rate assumed over the forecast horizon was 2 percent.
- The AFUDC rate for new projects is set at the marginal cost of capital 7.95 percent.
- The weighted average cost of capital of 7.95 percent was used as the discount rate, and was based on the currently authorized 9.40 percent return on equity ("ROE").
- The assumed marginal cost of new long-term debt ranges between 4.49 percent and 4.84 percent based on current pricing information.
- A 21 percent statutory income tax rate.
- 100 percent recovery of all above-the-line costs incurred (including energy, operating and capital).
- The CER model assumes, for each of the retired coal-fired generating units, the continued depreciation of plant balances based on the pre-existing retirement dates of each unit. This assumption essentially reflects the amortization of a regulatory asset in the amount of the unamortized balance on the retirement date using the pre-existing depreciation schedule.

The major financial modeling assumptions for Sierra are described below and are the same for the entire planning period unless otherwise noted.

- Sierra's next general rate increase/decrease will go into effect January 1, 2020.
- Inflation Rate assumed over the forecast horizon was 2 percent.
- The AFUDC rate for new projects is set at the marginal cost of capital 6.65 percent.
- The weighted average cost of capital of 6.65 percent was used as the discount rate, and was based on the currently authorized 9.60 percent ROE.
- The assumed marginal cost of new debt ranges between 3.78 percent and 5.38 percent based on current pricing information.
- A 21 percent statutory income tax rate.
- 100 percent recovery of all above-the-line costs incurred (including energy, operating and capital).

- The CER model assumes, for each of the retired coal-fired generating units, the continued depreciation of plant balances based on the pre-existing retirement dates of each unit. This assumption essentially reflects the amortization of a regulatory asset in the amount of the unamortized balance on the retirement date using the pre-existing depreciation schedule.

G. RISK MANAGEMENT STRATEGY

The Companies' risk management strategies are presented in Section 7 of the 2018 ESP. The risk management strategy is structured to mitigate risk in the following respects:

Evaluation of Options. Risk minimization activities start with the planning process and the decisions for demand or supply options that are examined and eventually integrated into the Companies' IRPs and ESPs. Starting with the load forecast, the Companies establish customers' needs, including appropriate reserve margins. Once those needs are known, options available to meet those needs are then assessed. The process includes an examination of market fundamentals in the region, including the outlook for change over the planning horizon.

Reduce Reliance on Volatile Wholesale Energy Markets. The Companies' longer-term risk management strategies have included increasing the level of longer term power purchase contracts and company-owned generation to reduce exposure to volatility to the capacity portion (scarcity premiums) of the Companies' energy supply costs.

Use of Competitive Procurement Processes. While the 2018 Joint IRP significantly reduces the Companies' energy and capacity requirements, the Companies may issue RFPs in the future, if warranted, to cover unanticipated needs at competitive costs. As part of the risk management plan, an economic analysis of the bid responses will be conducted and the selected options will enter negotiations for contracting as appropriate.

The Financial Plan assumes implementation of the risk management strategy.

H. FINANCIAL RISKS

This section discusses in more detail several financial matters which are important in assessing the Companies' Preferred and Alternative plans.

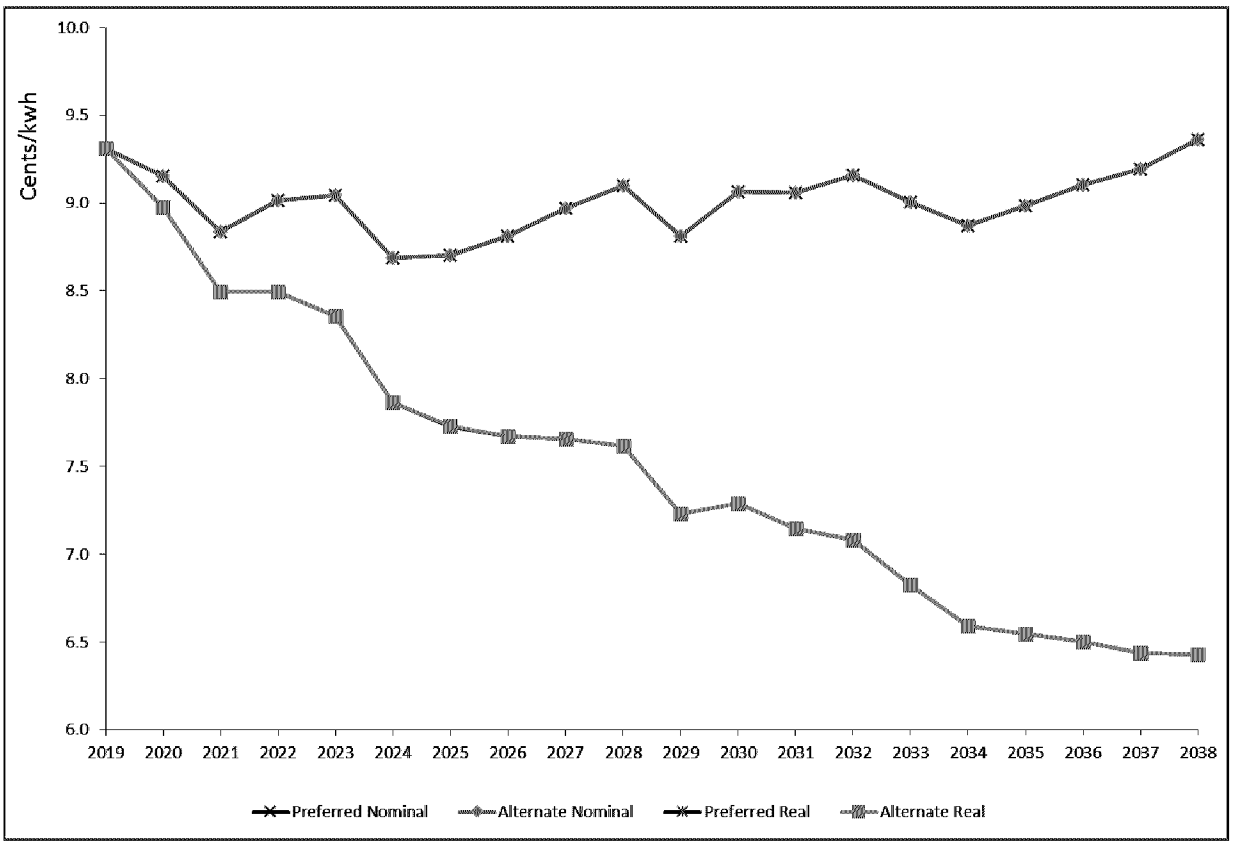
1. EXTERNAL FINANCING COSTS

Due to the ongoing need to access external capital, the Companies must continue to rely on access to the financial markets. Increasing volatility in, and over-reliance on, financial markets could lead to excessive financing costs for customers in order to fund future investments on their behalf.

2. IMPACT ON AVERAGE SYSTEM COST

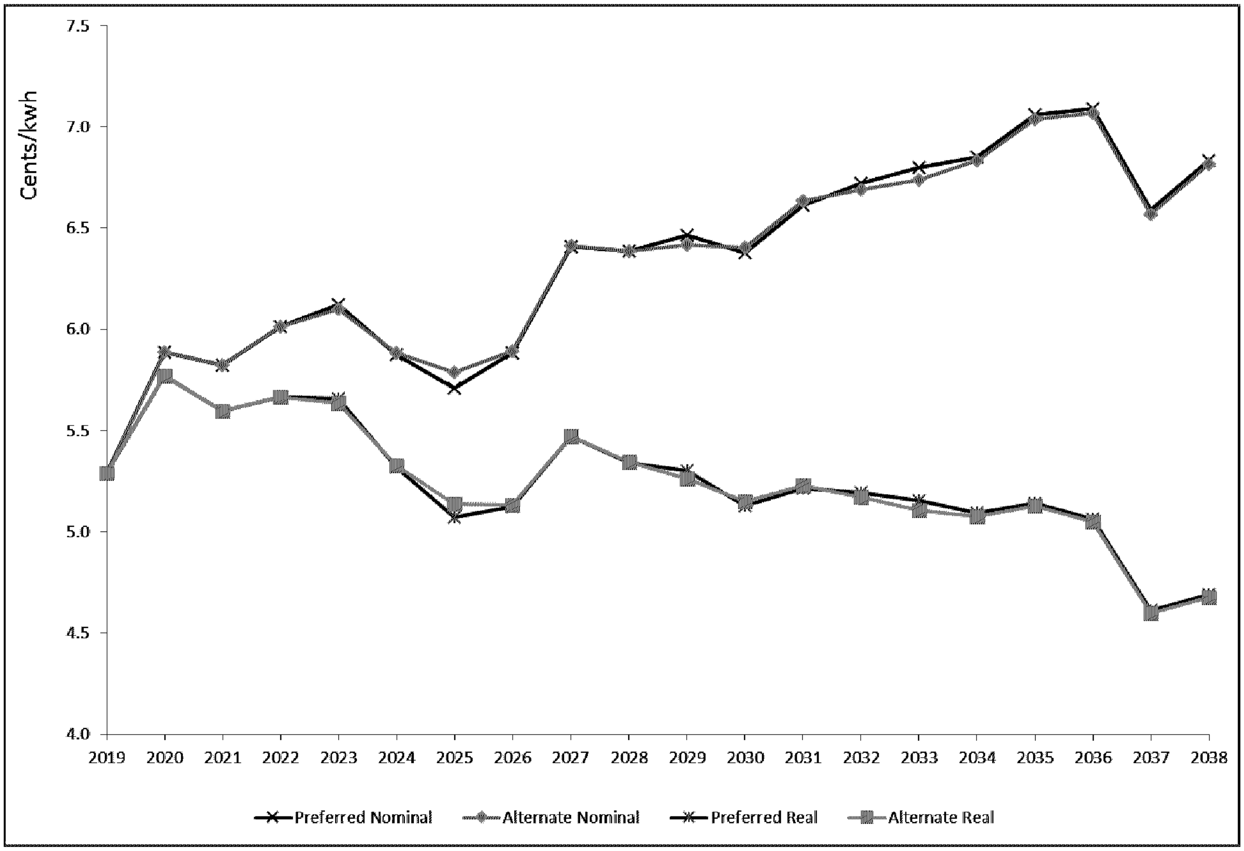
As shown in the Figure FP-9, the nominal average system cost per kWh for Nevada Power under this Financial Plan increases from 9.31 cents in 2019 to 9.36 cents in 2038 under both the Preferred and Alternative plans. The compound annual growth rate for the nominal average system cost over the forecast period is 0.03 percent for both plans. Average system costs are essentially projected to remain flat on average over the next 20 years on a nominal basis, and when inflation is reflected then the average system costs are forecasted to decline on a real basis.

FIGURE FP-9
NEVADA POWER
NOMINAL & REAL AVERAGE SYSTEM COST (CENTS/KWH)



For Sierra, Figure FP-10 illustrates that the nominal average system cost per kWh is projected to increase slightly over the 20 years from 5.29 cents in 2019 to 6.83 cents in 2038 under the Preferred Plan, and from 5.29 cents to 6.82 cents under the Alternative Plan. The compound annual growth rate for the nominal average system cost over the forecast period is 1.29 percent, and 1.28 percent, for each case respectively. The result is an increasing average system cost per kWh on a nominal basis but a decreasing cost on a real basis.

FIGURE FP-10
SIERRA
NOMINAL & REAL AVERAGE SYSTEM COST (CENTS/KWH)



3. CREDIT QUALITY

The Companies' secured debt is rated investment grade by all three rating agencies. The Companies' have maintained adequate liquidity and demonstrated the ability to successfully access the debt markets at low rates. Annual projected credit metrics for Nevada Power are shown in Figures FP-11 through FP-14 and Sierra's are illustrated in Figures FP-15 through FP-18.

Figures FP-14 and FP-18 summarize the cash generated from operations relative to capital expenditures for Nevada Power and Sierra, respectively. For the Companies, cash generated from operations exceeds capital expenditures for each of the annual periods in both the Preferred and Alternative plans. Despite the ability to fund capital expenditures with internally generated cash, Figures FP-3 and FP-4 clearly illustrate the Companies' ongoing need to access external capital at favorable rates in order to minimize customer rates.

Figure FP-15 illustrates the necessity for a higher equity level at Sierra. The funds from operations to total debt ratio is well below the targeted level for one year and barely meets the target for other periods. While Sierra's credit metrics raised some concerns, the higher equity ratio (i.e., 52 percent) used in the financial plan should deflect any potential negative actions by the rating agencies and help ensure debt costs are controlled. To the best of their abilities, the Companies will manage their capital structures in a way that mitigates any potential negative pressure on credit quality from the 2018 Joint IRP but regulatory support remains an important factor in the credit ratings process.

FIGURE FP-11
NEVADA POWER
FUNDS FROM OPERATIONS TO TOTAL DEBT (%)

[redacted]

FIGURE FP-12
NEVADA POWER
EBITDA INTEREST COVERAGE

[redacted]

FIGURE FP-13
NEVADA POWER
TOTAL DEBT TO TOTAL CAPITAL (%)

[redacted]

FIGURE FP-14
NEVADA POWER
CASH FROM OPERATIONS TO CAPEX
($ - MILLIONS)

[redacted]

FIGURE FP-15
SIERRA
FUNDS FROM OPERATIONS TO TOTAL DEBT (%)

[redacted]

FIGURE FP-16
SIERRA
EBITDA INTEREST COVERAGE

[redacted]

FIGURE FP-17
SIERRA
TOTAL DEBT TO TOTAL CAPITAL (%)

[redacted]

FIGURE FP-18
SIERRA
CASH FROM OPERATIONS TO CAPEX
($ - MILLIONS)

[redacted]

4. GREEN HOUSE GAS COSTS

The Financial Plan assumes that the Companies will recover 100 percent of all costs incurred to comply with future legislation regulating carbon emissions through the deferred energy mechanism.

I. CONCLUSION

The Companies have the capacity to finance the Preferred and Alternative plans as modeled in the Financial Plan without any expected negative impacts on credit ratings or capital costs. However, an ongoing need to access external capital at attractive rates requires regulatory support and continued reliance on financial markets.

GEN-1

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NV Energy Generation Summary

Plant	I/S Date	Projected Retirement Date	(BTU/kWh)	Net Cap (MW)	Type
North					
~~Clark Mt. 1~~	~~1961~~	*Retired*	[redacted]	~~10 / 10~~	~~GTG/Diesel~~
~~Clark Mt. 2~~	~~1963~~	*Retired*	[redacted]	~~10 / 10~~	~~GTG/Diesel~~
Clark Mt. 3	1994	*2024*	[redacted]	72 / 66	GTG/Gas
Clark Mt. 4	1994	*2024*	[redacted]	72 / 66	GTG/Gas
Ft. Churchill 1	1968	*2025*	[redacted]	113 / 113	STG/Gas
Ft. Churchill 2	1971	*2028*	[redacted]	113 / 113	STG/Gas
~~Tracy 1~~	~~1963~~	*Retired*	[redacted]	~~53 / 53~~	~~STG/Gas~~
~~Tracy 2~~	~~1965~~	*Retired*	[redacted]	~~83 / 83~~	~~STG/Gas~~
Tracy 3	1974	*2028*	[redacted]	108 / 108	STG/Gas
Tracy 4&5 (Pinon)	1996	*2031*	[redacted]	108 / 104	CC/Steam
Tracy 8, 9, 10	2008	*2043*	[redacted]	578 / 553	CC/Steam
Valmy 1	1981	*2025*	[redacted]	254 / 254	STG/Coal
Valmy 2	1985	*2025*	[redacted]	268 / 268	STG/Coal
~~Battle Mt~~	~~1960~~	*Retired*	[redacted]	~~8~~	~~Recip/Oil~~
Brunswick	1960	***BLACKSTART ONLY***	[redacted]	6	Recip/Oil
~~Gabbs~~	~~1969~~	*Retired*	[redacted]	~~5.4~~	~~Recip/Oil~~
Kings Beach	2008	2058	[redacted]	12	Recip/Oil
~~Portola~~	~~1960~~	*Retired*	[redacted]	~~6~~	~~Recip/Oil~~
~~Valley Road~~	~~1960~~	*Retired*	[redacted]	~~6~~	~~Recip/Oil~~
~~Winnemucca CT~~	~~1970~~	*Retired*	[redacted]	~~14/14~~	~~CT/Gas~~
South					
~~Clark 1~~	~~1955~~	*Retired*	[redacted]	~~42 / 42~~	~~STG/Gas~~
~~Clark 2~~	~~1957~~	*Retired*	[redacted]	~~69 / 66~~	~~STG/Gas~~
~~Clark 3~~	~~1961~~	*Retired*	[redacted]	~~70 / 67~~	~~STG/Gas~~
Clark 4	1973	*2020*	[redacted]	63 / 55	GTG/Gas
Clark 5	1979	*2034*	[redacted]	84 / 73	GTG/Gas
Clark 6	1979	*2034*	[redacted]	84 / 73	GTG/Gas
Clark 7	1980	*2033*	[redacted]	84 / 73	GTG/Gas
Clark 8	1982	*2033*	[redacted]	84 / 73	GTG/Gas
Clark 9	1993	*2033*	[redacted]	82 / 84	CC/Steam
Clark 10	1994	*2034*	[redacted]	82 / 84	CC/Steam
Clark 11 - 22	2008	*2038*	[redacted]	57 / 52	GTG/Gas
Harry Allen 3	1995	*2025*	[redacted]	84 / 74	GTG/Gas
Harry Allen 4	2006	*2036*	[redacted]	84 / 74	GTG/Gas
Harry Allen CC	2011	*2046*	[redacted]	524 / 510	CC/Gas
Lenzie CC 1	2006	*2041*	[redacted]	601 / 585	CC/Gas
Lenzie CC 2	2006	*2041*	[redacted]	601 / 585	CC/Gas
~~RG 1~~	~~1965~~	*Retired*	[redacted]	~~100 / 100~~	~~STG/Coal~~
~~RG 2~~	~~1968~~	*Retired*	[redacted]	~~100 / 100~~	~~STG/Coal~~
~~RG 3~~	~~1976~~	*Retired*	[redacted]	~~100 / 100~~	~~STG/Coal~~
~~RG 4~~	~~1983~~	*Retired*	[redacted]	~~257 / 257~~	~~STG/Coal~~
Silverhawk CC	2004	*2039*	[redacted]	599 / 560	CC/Gas
Higgins CC	2004	*2039*	[redacted]	600 / 550	CC/Gas
~~Sunrise 1~~	~~1964~~	*Retired*	[redacted]		~~STG/Gas~~
~~Sunrise 2~~	~~1974~~	*Retired*	[redacted]		~~GTG/Gas~~
Navajo 1	1974	*2024*	[redacted]	85 (NPC share)	STG/Coal
Navajo 2	1975	*2025*	[redacted]	85 (NPC share)	STG/Coal
Navajo 3	1976	*2026*	[redacted]	85 (NPC share)	STG/Coal
LVCogen 1	1994	*2029*	[redacted]	51 / 48	CC/Gas
LVCogen 2	2004	*2039*	[redacted]	115 / 112	CC/Gas
LVCogen 3	2004	*2039*	[redacted]	115 / 112	CC/Gas
Sunpeak 3	1991	*2026*	[redacted]	74 / 72	GTG/Gas
Sunpeak 4	1991	*2026*	[redacted]	74 / 72	GTG/Gas
Sunpeak 5	1991	*2026*	[redacted]	74 / 72	GTG/Gas

NEW

CONFIDENTIAL - COMPANY USE ONLY

Unit		Min. Net Capacity (MW)	Assumed Net Capability (MW) Winter	Summer	Peak
FT Churchill Complex					
Ft. Churchill 1	ST	15	113	113	113
Ft. Churchill 1	ST	15	113	113	113
Tracy Complex					
Tracy 3	ST	28	108	108	108
Tracy 4	GT	30	68	65	65
Tracy 5	ST		25	24	24
Tracy 4 duct burn			15	15	15
Tracy 4/5	CC	51.5	93	89	89
Tracy 4/5 + ducts	CC		108	104	104
Tracy 8	GT	100	146	145	144
Tracy 9	GT	100	146	145	144
Tracy 10	ST		145	143	140
Tracy CC duct burn			141	120	113
Tracy CC (1X1)	CC	124	218.5	216.5	214
Tracy CC (1X1 + ducts)	CC		289	276.5	270.5
Tracy CC (2X1)	CC	285	437	433	428
Tracy CC (2X1 + ducts)	CC		578	553	541
Clark Mountain 3	GT	35	72	66	66
Clark Mountain 4	GT	35	72	66	66
Valmy Complex					
Valmy 1 (full plant output)	ST	85	254	254	254
Valmy 2 (full plant output)	ST	90	268	268	268
Valmy 1 (SPPC portion only)	ST	42.5	127	127	127
Valmy 2 (SPPC portion only)	ST	45	134	134	134
Clark Complex					
Clark 4	GT	20	63	55	54
Clark 5	GT	35	84	73	72
Clark 6	GT	35	84	73	72
Clark 10	ST		82	84	71
Clark 10 CC - (5,6,10) 1x1	CC	52	166	157	143
Clark 10 CC - (5,6,10) 2x1	CC	115	250	230	215
Clark 7	GT	31	84	73	72
Clark 8	GT	31	84	73	72
Clark 9	ST		82	84	71
Clark 9 CC - (7,8,9) 1x1	CC	52	166	157	143
Clark 9 CC - (7,8,9) 2x1	CC	115	250	230	215
Clark 11-22	GT	35	57	52	51.5
Chuck Lenzie Complex					
LZ 1 CT1	GT	100	168	165	158
LZ 1 CT2	GT	100	168	165	158
Lenzie STG1	ST		165	160	143
Lenzie 1 duct burn			100	95	92
Lenzie CC 1 (1x1)	CC		251	245	230
Lenzie CC 1 (1x1 + ducts)	CC		301	293	276
Lenzie CC 1 (2x1)	CC	300	501	490	459
Lenzie CC 1 (2x1 + ducts)	CC		601	585	551
LZ 2 CT3	GT	100	168	165	158
LZ 2 CT4	GT	100	168	165	158
Lenzie STG2	ST		165	160	143
Lenzie 2 duct burn			100	95	92
Lenzie CC 2 (1x1)	CC		251	245	230
Lenzie CC 2 (1x1 + ducts)	CC		301	293	276
Lenzie CC 2 (2x1)	CC	300	501	490	459
Lenzie CC 2 (2x1 + ducts)	CC		601	585	551
Silverhawk Station					
SH CTA	GT	100	170	157	145
SH CTB	GT	100	170	157	145
SH STG	ST		159	151	140
SH duct burn			100	95	90
Silverhawk CC (1x1)	CC	170	250	233	215
Silverhawk CC (1x1 + ducts)	CC		300	280	260
Silverhawk CC (2x1)	CC	315	499	465	430
Silverhawk (2x1 + ducts)	CC		599	560	520
Harry Allen Station					
Harry Allen 3	GT	35	84	74	72
Harry Allen 4	GT	35	84	74	72
Harry Allen 5	GT	80	165		
Harry Allen 6	GT	80	165		
Harry Allen 7	ST				
Harry Allen duct burn (Per CT)					
Harry Allen CC (1x1)	CC	135	242		
Harry Allen CC (1x1 + ducts)	CC		267		
Harry Allen CC (2x1)	CC	275	489		
Harry Allen (2x1 + ducts)	CC		524	510	484
Higgins Station					
CT1	GT	80	162		
CT2	GT	80	162		
STG	ST				
Higgins CC duct burn (Per CT)					
Higgins CC (1x1)	CC	165	232		
Higgins CC (1x1 + ducts)	CC		282		
Higgins CC (2x1)	CC	350	494		
Higgins CC (2x1 + ducts)	CC		600	550	530
Las Vegas Cogen					
LV Cogen 1 - 1x0					
LV Cogen 1 - 1x1	CC	25	51	48	48
LV Cogen 2 - 1x0					
LV Cogen 2 - 1x1	CC	25	55		
LV Cogen 2 - 2x1	CC	50	115	112	112
LV Cogen 3 - 1x0					
LV Cogen 3 - 1x1	CC	25	55		
LV Cogen 3 - 2x1	CC	50	115	112	112
SunPeak					
Sunpeak 3	GT	65	74	72	70
Sunpeak 4	GT	65	74	72	70
Sunpeak 5	GT	65	74	72	70

RED indicates change from last version.

NVE Gen Unit Characteristics Table - 2018 Update (12292017).xlsx

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Unit	Minimum Run Time (minutes)	Minimum Down Time (minutes)	EIM Minimum Run Time (minutes)	EIM Minimum Down Time (minutes)	Minimum Time from Cold Start to On-Line - Normal (minutes)	Minimum Time from Cold Start to On-Line - Fast (minutes)	Minimum Time from Cold Start to On-Line - Drained (minutes)	EIM Minimum (MW)	EIM Maximum (MW)	AGC Minimum (MW)	AGC Maximum (MW)	EIM Minimum Ramp Rate (MW/Min)	EIM Maximum Ramp Rate (MW/Min)	Control Operator Ramp Rate (MW/Min) Slow	Control Operator Ramp Rate (MW/Min) Fast	Average Unplanned Outage Rate	Gross MVAR Capability Leading	Gross MVAR Capability Lagging	NPC Notes:
FT Churchill Complex	[redacted]																		
Ft. Churchill 1	[redacted]																		
Ft. Churchill 1	[redacted]																		
Tracy Complex	[redacted]																		
Tracy 3	[redacted]																		
Tracy 4	[redacted]																		
Tracy 4&5	[redacted]																		
Tracy 4/5 duct burn	[redacted]																		
Tracy 8	[redacted]																		
Tracy 9	[redacted]																		
Tracy CC (1X1)	[redacted]																		
Tracy CC (1X1 + ducts)	[redacted]																		
Tracy CC (2X1)	[redacted]																		
Tracy CC (2X1 + ducts)	[redacted]																		
Clark Mountain 3	[redacted]																		
Clark Mountain 4	[redacted]																		
Valmy Complex	[redacted]																		
Valmy 1 (full plant output)	[redacted]																		
Valmy 2 (full plant output)	[redacted]																		
Valmy 1 (SPPC portion only)	[redacted]																		
Valmy 2 (SPPC portion only)	[redacted]																		
Clark Complex	[redacted]																		
Clark 4	[redacted]																		Adjusted EFORd to predictive value
Clark 5	[redacted]																		
Clark 6	[redacted]																		
Clark 10 CC - (5,6,10) 1x1	[redacted]																		
Clark 10 CC - (5,6,10) 2x1	[redacted]																		
Clark 7	[redacted]																		
Clark 8	[redacted]																		
Clark 9 CC - (7,8,9) 1x1	[redacted]																		
Clark 9 CC - (7,8,9) 2x1	[redacted]																		
Clark 11-22	[redacted]																		Assumed EFORd- not based on actual performance
Chuck Lenzie Complex	[redacted]																		
LZ 1 CT1	[redacted]																		
LZ 1 CT2	[redacted]																		
Lenzie CC 1 (1x1)	[redacted]																		
Lenzie CC 1 (1x1 + ducts)	[redacted]																		
Lenzie CC 1 (2x1)	[redacted]																		
Lenzie CC 1 (2x1 + ducts)	[redacted]																		
LZ 2 CT3	[redacted]																		
LZ 2 CT4	[redacted]																		
Lenzie CC 2 (1x1)	[redacted]																		
Lenzie CC 2 (1x1 + ducts)	[redacted]																		
Lenzie CC 2 (2x1)	[redacted]																		
Lenzie CC 2 (2x1 + ducts)	[redacted]																		

REDACTED PUBLIC VERSION

NVE Gen Unit Characteristics Table - 2018 Update (12292017).xlsx

CONFIDENTIAL - COMPANY USE ONLY

Unit	Minimum Run Time (minutes)	Minimum Down Time (minutes)	EIM Minimum Run Time (minutes)	EIM Minimum Down Time (minutes)	Minimum Time from Cold Start to On-Line - Normal (minutes)	Minimum Time from Cold Start to On-Line - Fast (minutes)	Minimum Time from Cold Start to On-Line - Drained (minutes)	EIM Minimum (MW)	EIM Maximum (MW)	AGC Minimum (MW)	AGC Maximum (MW)	EIM Minimum Ramp Rate (MW/Min)	EIM Maximum Ramp Rate (MW/Min)	Control Operator Ramp Rate (MW/Min) Slow	Control Operator Ramp Rate (MW/Min) Fast	Average Unplanned Outage Rate	Gross MVAR Capability Leading	Gross MVAR Capability Lagging	NPC Notes:
Silverhawk Station	[redacted]																		
SH CTA																			
SH CTB																			
Silverhawk CC (1x1)																			
Silverhawk CC (1x1 + ducts)																			
Silverhawk CC (2x1)																			
Silverhawk (2x1 + ducts)																			
Harry Allen Station																			
Harry Allen 3																			
Harry Allen 4																			
Harry Allen 5																			
Harry Allen 6																			
Harry Allen CC (1x1)																			
Harry Allen CC (1x1 + ducts)																			
Harry Allen CC (2x1)																			
Harry Allen (2x1 + ducts)																			
Higgins Station																			
CT1																			
CT2																			
Higgins CC (1x1)																			
Higgins CC (1x1 + ducts)																			
Higgins CC (2x1)																			
Higgins CC (2x1 + ducts)																			
Las Vegas Cogen																			
LV Cogen 1 - 1x0																			
LV Cogen 1 - 1x1																			CT: -2.5/21, ST: -1.8/3
LV Cogen 2 - 1x0																			
LV Cogen 2 - 1x1																			
LV Cogen 2 - 2x1																			CTA:-7.5/32.3, CTB: -0.5/26.8, ST2: -7.1/19
LV Cogen 3 - 1x0																			
LV Cogen 3 - 1x1																			
LV Cogen 3 - 2x1																			CTA:-9.6/20.1, CTB:-2.3/20.2, ST3: -7.1/27.7
SunPeak																			
Sunpeak 3																			
Sunpeak 4																			
Sunpeak 5																			
Co-Owned/Non-Operated Facilities																			
Navajo 1,2,3																			

RED indicates change from last version.
(model) indicates value suggested for use in production cost models

REDACTED PUBLIC VERSION

NVE Gen Unit Characteristics Table - 2018 Update (12292017).xlsx

CONFIDENTIAL - COMPANY USE ONLY

Unit	Prime Mover/ Primary Fuel	Start-Up Fuel	Secondary Fuel	EIM Start-UP Energy (MMBTU Only) Normal	EIM Start-UP Energy (MMBTU Only) Cold	No-Load Heat Input (MMBTU/hr) [Heat Input Coefficent C]	Min Load Net Heat Rate (BTU/KWh)	Max Load Net Heat Rate (BTU/KWh)	Average of Min and Max Net Heat Rate (BTU/KWh)
FT Churchill Complex				[redacted]					
Ft. Churchill 1	STG/Gas	Gas	-						
Ft. Churchill 1	STG/Gas	Gas	-						
Tracy Complex									
Tracy 3	STG/Gas	Gas	-						
Tracy 4	GTG/Gas	Gas	-						
Tracy 4&5	CC/Steam - Gas	Gas	-						
Tracy 4/5 duct burn	CC/Steam - Gas	Gas	-						
Tracy 8	GTG/Gas	Gas	-						
Tracy 9	GTG/Gas	Gas	-						
Tracy CC (1X1)	CC/Steam - Gas	Gas	-						
Tracy CC (1X1 + ducts)	CC/Steam - Gas	Gas	-						
Tracy CC (2X1)	CC/Steam - Gas	Gas	-						
Tracy CC (2X1 + ducts)	CC/Steam - Gas	Gas	-						
Clark Mountain 3	GTG/Gas	Gas	Diesel #2 Oil						
Clark Mountain 4	GTG/Gas	Gas	Diesel #2 Oil						
Valmy Complex									
Valmy 1 (full plant output)	STG/Coal	Diesel #2 Oil	-						
Valmy 2 (full plant output)	STG/Coal	Diesel #2 Oil	-						
Valmy 1 (SPPC portion only)	STG/Coal	Diesel #2 Oil	-						
Valmy 2 (SPPC portion only)	STG/Coal	Diesel #2 Oil	-						
Clark Complex									
Clark 4	GTG/Gas	Gas	-						
Clark 5	GTG/Gas	Gas	-						
Clark 6	GTG/Gas	Gas	-						
Clark 10 CC - (5,6,10) 1x1	CC/Steam - Gas	Gas	-						
Clark 10 CC - (5,6,10) 2x1	CC/Steam - Gas	Gas	-						
Clark 7	GTG/Gas	Gas	-						
Clark 8	GTG/Gas	Gas	-						
Clark 9 CC - (7,8,9) 1x1	CC/Steam - Gas	Gas	-						
Clark 9 CC - (7,8,9) 2x1	CC/Steam - Gas	Gas	-						
Clark 11-22 (WINTER)	GTG/Gas	Gas	-						

REDACTED PUBLIC VERSION

NVE Gen Unit Characteristics Table - 2018 Update (12292017).xlsx

CONFIDENTIAL - COMPANY USE ONLY

Unit	Prime Mover/ Primary Fuel	Start-Up Fuel	Secondary Fuel	EIM Start-UP Energy (MMBTU Only) Normal	EIM Start-UP Energy (MMBTU Only) Cold	No-Load Heat Input (MMBTU/hr) [Heat Input Coefficent C]	Min Load Net Heat Rate (BTU/KWh)	Max Load Net Heat Rate (BTU/KWh)	Average of Min and Max Net Heat Rate (BTU/KWh)
Chuck Lenzie Complex				[redacted]					
LZ 1 CT1	GTG/Gas	Gas	-						
LZ 1 CT2	GTG/Gas	Gas	-						
Lenzie CC 1 (1x1)	CC/Steam - Gas	Gas	-						
Lenzie CC 1 (1x1 + ducts)	CC/Steam - Gas	Gas	-						
Lenzie CC 1 (2x1)	CC/Steam - Gas	Gas	-						
Lenzie CC 1 (2x1 + ducts)	CC/Steam - Gas	Gas	-						
LZ 2 CT3	GTG/Gas	Gas	-						
LZ 2 CT4	GTG/Gas	Gas	-						
Lenzie CC 2 (1x1)	CC/Steam - Gas	Gas	-						
Lenzie CC 2 (1x1 + ducts)	CC/Steam - Gas	Gas	-						
Lenzie CC 2 (2x1)	CC/Steam - Gas	Gas	-						
Lenzie CC 2 (2x1 + ducts)	CC/Steam - Gas	Gas	-						
Silverhawk Station									
SH CTA	GTG/Gas	Gas	-						
SH CTB	GTG/Gas	Gas	-						
Silverhawk CC (1x1)	CC/Steam - Gas	Gas	-						
Silverhawk CC (1x1 + ducts)	CC/Steam - Gas	Gas	-						
Silverhawk CC (2x1)	CC/Steam - Gas	Gas	-						
Silverhawk (2x1 + ducts)	CC/Steam - Gas	Gas	-						
Harry Allen Station									
Harry Allen 3	GTG/Gas	Gas	-						
Harry Allen 4	GTG/Gas	Gas	-						
Harry Allen 5	GTG/Gas	Gas	-						
Harry Allen 6	GTG/Gas	Gas	-						
Harry Allen CC (1x1)	CC/Steam - Gas	Gas	-						
Harry Allen CC (1x1 + ducts)	CC/Steam - Gas	Gas	-						
Harry Allen CC (2x1)	CC/Steam - Gas	Gas	-						
Harry Allen (2x1 + ducts)	CC/Steam - Gas	Gas	-						

NVE Gen Unit Characteristics Table - 2018 Update (12292017).xlsx

CONFIDENTIAL - COMPANY USE ONLY

Unit	Prime Mover/ Primary Fuel	Start-Up Fuel	Secondary Fuel	EIM Start-UP Energy (MMBTU Only) Normal	EIM Start-UP Energy (MMBTU Only) Cold	No-Load Heat Input (MMBTU/hr) [Heat Input Coefficent C]	Min Load Net Heat Rate (BTU/KWh)	Max Load Net Heat Rate (BTU/KWh)	Average of Min and Max Net Heat Rate (BTU/KWh)
Higgins Station				[redacted]					
CT1	GTG/Gas	Gas	-						
CT2	GTG/Gas	Gas	-						
Higgins CC (1x1)	CC/Steam - Gas	Gas	-						
Higgins CC (1x1 + ducts)	CC/Steam - Gas	Gas	-						
Higgins CC (2x1)	CC/Steam - Gas	Gas	-						
Higgins CC (2x1 + ducts)	CC/Steam - Gas	Gas	-						
Las Vegas Cogen									
LV Cogen 1 - 1x0	GTG/Gas	Gas	-						
LV Cogen 1 - 1x1	CC/Steam - Gas	Gas	-						
LV Cogen 2 - 1x0	GTG/Gas	Gas	-						
LV Cogen 2 - 1x1	CC/Steam - Gas	Gas	-						
LV Cogen 2 - 2x1	CC/Steam - Gas	Gas	-						
LV Cogen 3 - 1x0	GTG/Gas	Gas	-						
LV Cogen 3 - 1x1	CC/Steam - Gas	Gas	-						
LV Cogen 3 - 2x1	CC/Steam - Gas	Gas	-						
SunPeak									
Sunpeak 3	GTG/Gas	Gas	-						
Sunpeak 4	GTG/Gas	Gas	-						
Sunpeak 5	GTG/Gas	Gas	-						

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HEAT INPUT = A(MW^2)+B(MW)+C				
Unit	A	B	C	Inremental for Duct burners
FT Churchill Complex	[redacted]			
Ft. Churchill 1				
Ft. Churchill 1				
Tracy Complex				
Tracy 3				
Tracy 4				
Tracy 4&5				
Tracy 4/5 duct burn				
Tracy 8				
Tracy 9				
Tracy CC (1X1)				
Tracy CC (1X1 + ducts)				
Tracy CC (2X1)				
Tracy CC (2X1 + ducts)				
Clark Mountain 3				
Clark Mountain 4				
Valmy Complex				
Valmy 1 (full plant output)				
Valmy 2 (full plant output)				
Valmy 1 (SPPC portion only)				
Valmy 2 (SPPC portion only)				
Clark Complex				
Clark 4				
Clark 5				
Clark 6				
Clark 10 CC - (5,6,10) 1x1				
Clark 10 CC - (5,6,10) 2x1				
Clark 7				
Clark 8				
Clark 9 CC - (7,8,9) 1x1				
Clark 9 CC - (7,8,9) 2x1				
Clark 11-22				

NVE Gen Unit Characteristics Table - 2018 Update (12292017).xlsx

CONFIDENTIAL - COMPANY USE ONLY

HEAT INPUT = A(MW^2)+B(MW)+C

Unit	A	B	C	Inremental for Duct burners
Chuck Lenzie Complex	[redacted]			
LZ 1 CT1	[redacted]			
LZ 1 CT2	[redacted]			
Lenzie CC 1 (1x1)	[redacted]			
Lenzie CC 1 (1x1 + ducts)	[redacted]			
Lenzie CC 1 (2x1)	[redacted]			
Lenzie CC 1 (2x1 + ducts)	[redacted]			
LZ 2 CT3	[redacted]			
LZ 2 CT4	[redacted]			
Lenzie CC 2 (1x1)	[redacted]			
Lenzie CC 2 (1x1 + ducts)	[redacted]			
Lenzie CC 2 (2x1)	[redacted]			
Lenzie CC 2 (2x1 + ducts)	[redacted]			
Silverhawk Station	[redacted]			
SH CTA	[redacted]			
SH CTB	[redacted]			
Silverhawk CC (1x1)	[redacted]			
Silverhawk CC (1x1 + ducts)	[redacted]			
Silverhawk CC (2x1)	[redacted]			
Silverhawk (2x1 + ducts)	[redacted]			
Harry Allen Station	[redacted]			
Harry Allen 3	[redacted]			
Harry Allen 4	[redacted]			
Harry Allen 5	[redacted]			
Harry Allen 6	[redacted]			
Harry Allen CC (1x1)	[redacted]			
Harry Allen CC (1x1 + ducts)	[redacted]			
Harry Allen CC (2x1)	[redacted]			
Harry Allen (2x1 + ducts)	[redacted]			
Higgins Station	[redacted]			
CT1	[redacted]			
CT2	[redacted]			
Higgins CC (1x1)	[redacted]			
Higgins CC (1x1 + ducts)	[redacted]			
Higgins CC (2x1)	[redacted]			
Higgins CC (2x1 + ducts)	[redacted]			

CONFIDENTIAL - COMPANY USE ONLY

HEAT INPUT = A(MW^2)+B(MW)+C				
Unit	A	B	C	Inremental for Duct burners
Las Vegas Cogen	[redacted]			
LV Cogen 1 - 1x0				
LV Cogen 1 - 1x1				
LV Cogen 2 - 1x0				
LV Cogen 2 - 1x1				
LV Cogen 2 - 2x1				
LV Cogen 3 - 1x0				
LV Cogen 3 - 1x1				
LV Cogen 3 - 2x1				
SunPeak				
Sunpeak 3				
Sunpeak 4				
Sunpeak 5				

RED indicates change from last version.

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Previous Unit	Type	Summer KW Capacity	Fixed O&M per KW-Yr Includes Coal Yard DEAA	Fixed O&M Total (Including Coal Handling)	Fixed O&M Coal Handling (DEAA $ - These $ included in column D)
			FIXED O&M - 24 hr reserve status 24x7x365 (Based on Summer KW Capacity)	FIXED O&M - 24 hr reserve status 24x7x365	FIXED O&M - 24 hr reserve status 24x7x366
			Current	Current	Current
			2018 $	2018 $	2018 $
Ft Churchill			[redacted]		
Ft. Churchill 1	NG Boiler	113,000			
Ft. Churchill 2	NG Boiler	113,000			
Tracy Complex					
Tracy 3	NG Boiler	108,000			
Tracy 4&5	Small CC	104,000			
Tracy Combined Cycle 2x1	Large CC	553,000			
Tracy Combined Cycle 2x1 (with Duct	Large CC	553,000			
Tracy Combined Cycle 1x1	Large CC				
Tracy Combined Cycle 1x1 (with Duct	Large CC				
Tracy Combined Cycle 1x0	Large CC				
Clark Mountain 3	Peaker	66,000			
Clark Mountain 3 (Fast Start)	Peaker	66,000			
Clark Mountain 4	Peaker	66,000			
Clark Mountain 4 (Fast Start)	Peaker	66,000			
Valmy Complex					
Valmy 1	Coal Boiler	254,000			
Valmy 2	Coal Boiler	268,000			
Clark Complex					
Clark 7	Small CC	73,000			
Clark CC 1x1	Small CC				
Clark 9 CC - (Ck 7,8 & 9)	Small CC	230,000			
Clark 5	Small CC	73,000			
Clark CC 1x1	Small CC				
Clark 10 CC - (Ck 5,6 & 10)	Small CC	230,000			
Clark 4	Peaker	55,000			
Clark 11-22	Peaker	572,000			
Arrow Canyon Complex					
Lenzie Combined Cycle 2x1	Large CC	585,000			
Lenzie Combined Cycle 2x1 (with Duct Burners)	Large CC	585,000			
Lenzie Combined Cycle 1x1	Large CC	585,000			
Lenzie Combined Cycle 1x1 (with Duct Burners)	Large CC	585,000			
Lenzie Combined Cycle 1x0	Large CC				
Silverhawk Combined Cycle 2x1	Large CC	560,000			
Silverhawk Combined Cycle 2x1 (with Duct Burners)	Large CC				
Silverhawk Combined Cycle 1x1	Large CC				
Silverhawk Combined Cycle 1x1 (with Duct Burners)	Large CC				
Silverhawk Combined Cycle 1x0	Large CC				
Harry Allen Combined Cycle 2x1	Large CC	510,000			
Harry Allen Combined Cycle 2x1 (with Duct Burners)	Large CC	510,000			
Harry Allen Combined Cycle 1x1	Large CC				
Harry Allen Combined Cycle 1x1 (with Duct Burners)	Large CC				
Harry Allen Combined Cycle 1x0	Large CC				
Harry Allen 3	Peaker	74,000			
Harry Allen 3 (Fast Start)	Peaker	74,000			
Harry Allen 4	Peaker	74,000			
Harry Allen 4 (Fast Start)	Peaker	74,000			
Higgins Station					
Higgins Combined Cycle 2x1	Large CC	550,000			
Higgins Combined Cycle 2x1 (with Duct Burners)	Large CC	550,000			
Higgins Combined Cycle 1x1					
Higgins Combined Cycle 1x1 (with Duct Burners)					
Higgins Combined Cycle 1x0	Large CC				
Goodsprings					
Goodsprings	Renewable	5,000			
Las Vegas Station					
Las Vegas Block 1	Small CC	48,000			
LV Generation 2 or 3 1x1	Small CC	-			
Las Vegas Block 2	Small CC	112,000			
LV Generation 2 or 3 1x1	Small CC	-			
Las Vegas Block 3	Small CC	112,000			
Nellis Solar					
Nellis Solar	Renewable	5,000			
Sunpeak Station					
Sunpeak 3	Peaker	72,000			
Sunpeak 4	Peaker	72,000			
Sunpeak 5	Peaker	72,000			
Co-Owned/Non-Operated Facilities					
Navajo 1,2,3 (Combined)	Coal Boiler	255,000			

REDACTED PUBLIC VERSION

NVE Gen Unit Characteristics Table - 2018 Update (12292017).xlsx

CONFIDENTIAL - COMPANY USE ONLY			CONFIDENTIAL - COMPANY USE ONLY						CONFIDENTIAL - COMPANY USE ONLY
			Variable O&M (Consumables) per MWh O&M (Includes Coal Handling)	Variable O&M (Consumables) per MWh Coal Handling	Maint $ / MWH O&M (Includes Coal Handling)	Maint $ / MWH Coal Handling	Maint $ / operating hr O&M (Includes Coal Handling)	Maint $ / operating hr Coal Handling	Maint$ / start
			Variable O&M - Costs associated with Dispach of the units	Variable O&M - Costs associated with Dispach of the units	Variable O&M - Costs associated with Dispach of the units	Variable O&M - Costs associated with Dispach of the units	Variable O&M - Costs associated with Dispach of the units	Variable O&M - Costs associated with Dispach of the units	Variable O&M - Costs associated with Dispach of the units
			Current	Current	Current	Current	Current	Current	Current
Unit	Previous Unit	Type	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $
Ft Churchill			[redacted]						
Ft. Churchill 1	Ft. Churchill 1	NG Boiler							
Ft. Churchill 2	Ft. Churchill 2	NG Boiler							
Tracy Complex									
Tracy 3	Tracy 3	NG Boiler							
Tracy 4&5	Tracy 4&5	Small CC							
Tracy Combined Cycle 2x1	**Tracy Combined Cycle 2x1**	**Large CC**							
Tracy Combined Cycle 2x1 (with Duct Burners)	Tracy Combined Cycle 2x1 (with Duct Burners)	Large CC							
Tracy Combined Cycle 1x1	Tracy Combined Cycle 1x1	Large CC							
Tracy Combined Cycle 1x1 (with Duct Burners)	Tracy Combined Cycle 1x1 (with Duct Burners)	Large CC							
Tracy Combined Cycle 1x0	Tracy Combined Cycle 1x0	Large CC							
Clark Mountain 3	Clark Mountain 3	Peaker							
Clark Mountain 3 (Fast Start)	Clark Mountain 3 (Fast Start)	Peaker							
Clark Mountain 4	Clark Mountain 4	Peaker							
Clark Mountain 4 (Fast Start)	Clark Mountain 4 (Fast Start)	Peaker							
Valmy Complex									
Valmy 1	Valmy 1	Coal Boiler							
Valmy 2	Valmy 2	Coal Boiler							
Clark Complex									
Clark789 1x0	Clark 7	Small CC							
Clark789 1x1	Clark CC 1x1	Small CC							
Clark789 2x1	Clark 9 CC - (Ck 7,8 & 9)	Small CC							
Clark5610 1x0	Clark 5	Small CC							
Clark5610 1x1	Clark CC 1x1	Small CC							
Clark5610 2x1	Clark 10 CC - (Ck 5,6 & 10)	Small CC							
Clark 4	Clark 4	Peaker							
Clark Peakers 11-22	Clark 11-22	Peaker							
Arrow Canyon Complex									
Lenzie Combined Cycle 2x1	**Lenzie Combined Cycle 2x1**	**Large CC**							
Lenzie Combined Cycle 2x1 (with Duct Burners)	Lenzie Combined Cycle 2x1 (with Duct Burners)	Large CC							
Lenzie Combined Cycle 1x1	Lenzie Combined Cycle 1x1	Large CC							
Lenzie Combined Cycle 1x1 (with Duct Burners)	Lenzie Combined Cycle 1x1 (with Duct Burners)	Large CC							
Lenzie Combined Cycle 1x0	Lenzie Combined Cycle 1x0	Large CC							
Silverhawk Combined Cycle 2x1	**Silverhawk Combined Cycle 2x1**	**Large CC**							
Silverhawk Combined Cycle 2x1 (with Duct Burners)	Silverhawk Combined Cycle 2x1 (with Duct Burners)	Large CC							
Silverhawk Combined Cycle 1x1	Silverhawk Combined Cycle 1x1	Large CC							
Silverhawk Combined Cycle 1x1 (with Duct Burners)	Silverhawk Combined Cycle 1x1 (with Duct Burners)	Large CC							
Silverhawk Combined Cycle 1x0	Silverhawk Combined Cycle 1x0	Large CC							
Harry Allen Combined Cycle 2x1	**Harry Allen Combined Cycle 2x1**	**Large CC**							
Harry Allen Combined Cycle 2x1 (with Duct Burners)	Harry Allen Combined Cycle 2x1 (with Duct Burners)	Large CC							
Harry Allen Combined Cycle 1x1	Harry Allen Combined Cycle 1x1	Large CC							
Harry Allen Combined Cycle 1x1 (with Duct Burners)	Harry Allen Combined Cycle 1x1 (with Duct Burners)	Large CC							
Harry Allen Combined Cycle 1x0	Harry Allen Combined Cycle 1x0	Large CC							
Harry Allen 3	Harry Allen 3	Peaker							
Harry Allen 3 (Fast Start)	Harry Allen 3 (Fast Start)	Peaker							
Harry Allen 4	Harry Allen 4	Peaker							
Harry Allen 4 (Fast Start)	Harry Allen 4 (Fast Start)	Peaker							
I									
Higgins Station									
Higgins Combined Cycle 2x1	**Higgins Combined Cycle 2x1**	**Large CC**							
Higgins Combined Cycle 2x1 (with Duct Burners)	Higgins Combined Cycle 2x1 (with Duct Burners)	Large CC							
Higgins Combined Cycle 1x1	Higgins Combined Cycle 1x1	Large CC							
Higgins Combined Cycle 1x1 (with Duct Burners)	Higgins Combined Cycle 1x1 (with Duct Burners)	Large CC							
Higgins Combined Cycle 1x0	Higgins Combined Cycle 1x0	Large CC							
Goodsprings									
Goodsprings	Goodsprings	Renewable							
Las Vegas Station									
Las Vegas Block 1	Las Vegas Block 1	Small CC							
Las Vegas Block 2 1x0									
Las Vegas Block 2 1x1	LV Generation 2 or 3 1x1	Small CC							
Las Vegas Block 2 2x1	Las Vegas Block 2	Small CC							
Las Vegas Block 3 1x0									
Las Vegas Block 3 1x1	LV Generation 2 or 3 1x1	Small CC							
Las Vegas Block 3 2x1	Las Vegas Block 3	Small CC							
Nellis Solar									
Nellis Solar	Nellis Solar	Renewable							
Sunpeak Station									
Sunpeak 3	Sunpeak 3	Peaker							
Sunpeak 4	Sunpeak 4	Peaker							
Sunpeak 5	Sunpeak 5	Peaker							
Co-Owned/Non-Operated Facilities									
Navajo 1,2,3	Navajo 1,2,3	Coal Boiler							

NVE Gen Unit Characteristics Table - 2018 Update (12292017).xlsx

CONFIDENTIAL - COMPANY USE ONLY							CONFIDENTIAL - COMPANY USE ONLY				CONFIDENTIAL - COMPANY USE ONLY			
			Cold Start	Cold Start	Cold Start	Cold Start	Warm Start	Warm Start	Warm Start	Warm Start	Hot Start	Hot Start	Hot Start	Hot Start
			Single Generator (includes 1x0)	CC: 1x0 to 1x1	CC: 1x1 to 2x1	CC: 0 to 2x1	Single Generator (includes 1x0)	CC: 0 to 1x1	CC: 1x1 to 2x1	CC: 0 to 2x1	Single Generator (includes 1x0)	CC: 0 to 1x1	CC: 1x1 to 2x1	CC: 0 to 2x1
			Current	Current	Current	Current	Current	Current	Current	Current	Current	Current	Current	Current
Unit	Previous Unit	Type	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $	2018 $
Ft Churchill			[redacted]											
Ft. Churchill 1	Ft. Churchill 1	NG Boiler												
Ft. Churchill 2	Ft. Churchill 2	NG Boiler												
Tracy Complex														
Tracy 3	Tracy 3	NG Boiler												
Tracy 4&5	Tracy 4&5	Small CC												
Tracy Combined Cycle 2x1	**Tracy Combined Cycle 2x1**	**Large CC**												
Tracy Combined Cycle 2x1 (with Duct Burners)	Tracy Combined Cycle 2x1 (with Duct Burners)	Large CC												
Tracy Combined Cycle 1x1	Tracy Combined Cycle 1x1	Large CC												
Tracy Combined Cycle 1x1 (with Duct Burners)	Tracy Combined Cycle 1x1 (with Duct Burners)	Large CC												
Tracy Combined Cycle 1x0	Tracy Combined Cycle 1x0	Large CC												
Clark Mountain 3	Clark Mountain 3	Peaker												
Clark Mountain 3 (Fast Start)	Clark Mountain 3 (Fast Start)	Peaker												
Clark Mountain 4	Clark Mountain 4	Peaker												
Clark Mountain 4 (Fast Start)	Clark Mountain 4 (Fast Start)	Peaker												
Valmy Complex														
Valmy 1	Valmy 1	Coal Boiler												
Valmy 2	Valmy 2	Coal Boiler												
Clark Complex														
Clark789 1x0	Clark 7	Small CC												
Clark789 1x1	Clark CC 1x1	Small CC												
Clark789 2x1	Clark 9 CC - (Ck 7,8 & 9)	Small CC												
Clark5610 1x0	Clark 5	Small CC												
Clark5610 1x1	Clark CC 1x1	Small CC												
Clark5610 2x1	Clark 10 CC - (Ck 5,6 & 10)	Small CC												
Clark 4	Clark 4	Peaker												
Clark Peakers 11-22	Clark 11-22	Peaker												
Arrow Canyon Complex														
Lenzie Combined Cycle 2x1	**Lenzie Combined Cycle 2x1**	**Large CC**												
Lenzie Combined Cycle 2x1 (with Duct Burners)	Lenzie Combined Cycle 2x1 (with Duct Burners)	Large CC												
Lenzie Combined Cycle 1x1	Lenzie Combined Cycle 1x1	Large CC												
Lenzie Combined Cycle 1x1 (with Duct Burners)	Lenzie Combined Cycle 1x1 (with Duct Burners)	Large CC												
Lenzie Combined Cycle 1x0	Lenzie Combined Cycle 1x0	Large CC												
Silverhawk Combined Cycle 2x1	**Silverhawk Combined Cycle 2x1**	**Large CC**												
Silverhawk Combined Cycle 2x1 (with Duct Burners)	Silverhawk Combined Cycle 2x1 (with Duct Burners)	Large CC												
Silverhawk Combined Cycle 1x1	Silverhawk Combined Cycle 1x1	Large CC												
Silverhawk Combined Cycle 1x1 (with Duct Burners)	Silverhawk Combined Cycle 1x1 (with Duct Burners)	Large CC												
Silverhawk Combined Cycle 1x0	Silverhawk Combined Cycle 1x0	Large CC												
Harry Allen Combined Cycle 2x1	**Harry Allen Combined Cycle 2x1**	**Large CC**												
Harry Allen Combined Cycle 2x1 (with Duct Burners)	Harry Allen Combined Cycle 2x1 (with Duct Burners)	Large CC												
Harry Allen Combined Cycle 1x1	Harry Allen Combined Cycle 1x1	Large CC												
Harry Allen Combined Cycle 1x1 (with Duct Burners)	Harry Allen Combined Cycle 1x1 (with Duct Burners)	Large CC												
Harry Allen Combined Cycle 1x0	Harry Allen Combined Cycle 1x0	Large CC												
Harry Allen 3	Harry Allen 3	Peaker												
Harry Allen 3 (Fast Start)	Harry Allen 3 (Fast Start)	Peaker												
Harry Allen 4	Harry Allen 4	Peaker												
Harry Allen 4 (Fast Start)	Harry Allen 4 (Fast Start)	Peaker												
I														
Higgins Station														
Higgins Combined Cycle 2x1	**Higgins Combined Cycle 2x1**	**Large CC**												
Higgins Combined Cycle 2x1 (with Duct Burners)	Higgins Combined Cycle 2x1 (with Duct Burners)	Large CC												
Higgins Combined Cycle 1x1	Higgins Combined Cycle 1x1	Large CC												
Higgins Combined Cycle 1x1 (with Duct Burners)	Higgins Combined Cycle 1x1 (with Duct Burners)	Large CC												
Higgins Combined Cycle 1x0	Higgins Combined Cycle 1x0	Large CC												
Goodsprings														
Goodsprings	Goodsprings	Renewable												
Las Vegas Station														
Las Vegas Block 1	Las Vegas Block 1	Small CC												
Las Vegas Block 2 1x0														
Las Vegas Block 2 1x1	LV Generation 2 or 3 1x1	Small CC												
Las Vegas Block 2 2x1	Las Vegas Block 2	Small CC												
Las Vegas Block 3 1x0														
Las Vegas Block 3 1x1	LV Generation 2 or 3 1x1	Small CC												
Las Vegas Block 3 2x1	Las Vegas Block 3	Small CC												
Sunpeak Station														
Sunpeak 3	Sunpeak 3	Peaker												
Sunpeak 4	Sunpeak 4	Peaker												
Sunpeak 5	Sunpeak 5	Peaker												
Co-Owned/Non-Operated Facilities														
Navajo 1,2,3	Navajo 1,2,3	Coal Boiler												

GEN-2

CONFIDENTIAL
FILED UNDER SEAL

GEN-3

CONFIDENTIAL
FILED UNDER SEAL

GEN-4A

Life Span Analysis Process

Clark Peaking Unit 4
Clark County, Nevada

2018 Update

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1.0 EXECUTIVE SUMMARY

The recommendation of this Life Span Analysis Process ("LSAP") is to plan for the continued operation of the Clark Peaking Unit 4 ("Clark 4") through 2030. This recommendation would result in continuing the operation of this unit for an additional 10 years beyond its currently assigned retirement date. This recommendation is based primarily on the following factors: 1) there are no other known approved or pending environmental regulations that would materially affect this unit, and 2) this unit is currently operating reliably and is expected to continue to operate in a manner similar to its historic operation. The Clark Generating Station ("Clark Station") maintenance team conducts periodic inspections of Clark 4 to monitor the condition of the turbine components. Repairs are made as necessary and planned maintenance outages are taken based on the Original Equipment Manufacturer ("OEM"), General Electric's ("GE"), recommended intervals. Based on these inspections and repairs, Clark 4 is in good working condition and is expected to meet the expected mode of operation in the future.

Based on the reviews that were completed in developing this LSAP, Nevada Power recommends changing the planning retirement date to 2030. Nevada Power does have concerns regarding the continued operations of Clark 4, since it is already 44 years old. In the event that a major investment is required for this unit, Nevada Power would conduct another LSAP to determine whether the investment should be made, or if the unit should be retired.

2.0 UNIT DESCRIPTIONS

Clark 4 is located at the Clark Station, on the east side of the Las Vegas Valley. The operations and maintenance staff at the Clark Station operate, monitor and maintain these units, locally, on the plant site.

Clark 4 is a GE model 7B simple cycle combustion turbine ("CT") that is rated for a net dependable summer capacity of 54 MW. Clark 4 is designed to operate on natural gas as its primary fuel. The unit optimally operates at an approximate 14,000 BTU/kw-hr heat rate. Clark 4 has traditionally operated intermittently as a peaking unit to meet short-term demands in Nevada Power's system. Clark 4 began commercially operating in 1973 and has been operating for the past 44 years and has a projected retirement date of 2020.

Clark 4 currently meets all permitted emissions levels.

Figure 1 – Clark Unit 4

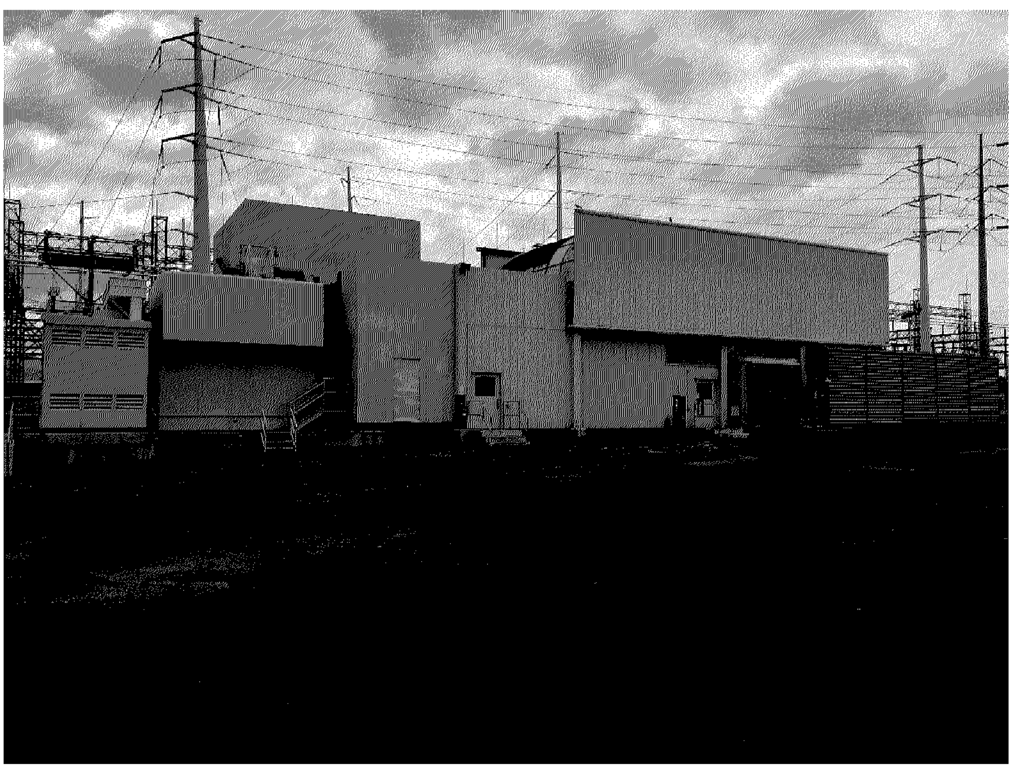
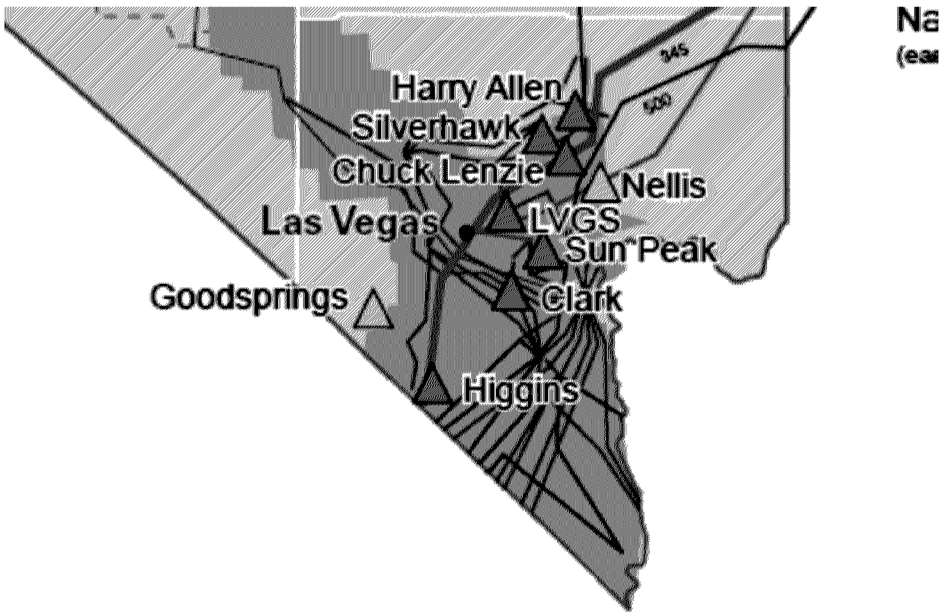


Figure 2 – Clark Station Location



2.1 Projected Operation

The following table presents the projected operations through 2025. Under the currently projected operating scenario, Clark 4 will continue to operate as a peaking unit, only operating on an as needed basis.

Figure 3 – Projected Operations – Annual Operating Hours

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Clark Unit 4	17	26	14	221	182	114	95	57	44	2

2.2 Projected O&M Budget

No specific Operations and Maintenance budget is set for Clark 4. Since the unit operates very infrequently, its maintenance is addressed on an as needed basis by the Clark Station Maintenance staff. No projected large maintenance expenses are projected in the next 10 years.

2.3 Projected Capital Budget

No capital expenditures are planned for Clark Unit 4 for the next 10 years. Investment requirements will be assessed on an as-needed basis.

3.0 LSAP REASSESSMENT CRITERIA

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. This initial life span is established when the unit is first put in service, or in the case of older units when the LSAP was approved by the Commission,[1] the Reassessment Protocol was used to set an initial life.

After a unit is commissioned and has been in operation, the life span may be reassessed to ensure that the initial Life Span Assessment is still valid, or to determine a new plan that is more appropriate for the unit. The reassessment of unit life span can be undertaken for any of the following **Reassessment Criteria**:

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Environmental Compliance
- Infrastructure
- Significant Event
- Commission Ordered Reassessment.

When a reassessment is undertaken, it can range from cursory to detailed, dependent on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the initial Life Span Assessment. The other end of the spectrum would be a unit entering its planned last decade of operations where operations, maintenance, environmental and infrastructure issues could dictate a detailed review to assess the remaining life span. No matter the nature of the review, the key steps of the **Reassessment Protocol** are as follows:

- Unit Assessment
- Environmental Assessment
- Infrastructure Assessment
- Development of Options
- Options Input to Resource Planning and Financial Analysis
- Final Decision on Life Span Assessment and Implementation Plan

Per the approved LSAP, the following reassessment criteria have been met, triggering an evaluation of the operating life for the Clark Mountain Units.

- Unit is within 10 years of last approved retirement date

The following provides a brief explanation of the above trigger and determines the criticality of each trigger for the LSAP analysis.

[1] The Life Span Analysis Process was approved by the Commission in Docket No. 08-08002

<u>Unit Is Within 10 Years of Last Approved Retirement Date</u>

The latest Integrated Resource Plan ("IRP") filing for Nevada Power shows a retirement date of December 31, 2020 for Clark 4. On this schedule, decommissioning and retirement would occur within the Action Plan period of the 2018 IRP. Any replacement capacity would take a number of years to permit, design and construct, and investments in replacement units would be required within the Action Plan period. Therefore, it is timely to review the 2020 retirement date at this time.

3.1 Unit Condition Considerations

Clark 4, is a GE Frame 7B combustion turbine ("CT") operating in simple-cycle mode, and was installed in 1973 as a peaking unit, and continues to operate approximately 100 hours per year. The unit was originally dual-fuel capable; however, it has operated in a gas-fuel only mode since May 6, 2007, and the diesel firing capability and permitting was removed.

The last major inspection of the unit was performed in the mid-1980s, and the last hot gas path inspection was in 1991.

There is no nitrogen oxide ("NO_x") suppression water injection used on Clark 4. The combustion system utilizes the original unmodified diffusion combustors and the original control curves, although a limitation on output has been imposed by Nevada Power due to high temperature readings on a wheel-space thermocouple; high temperature readings on the Generator Step-Up ("GSU") transformer; and high temperature readings on a generator stator winding resistance temperature detector ("RTD"). This limitation prevents the unit from achieving design (and permitted) output by approximately 17 percent (or about 10 MW).

The original GE turbine controls (Mark I) were upgraded to the plant-wide Ovation control system in the late 1990's. Ovation controls sequencing as well as turbine/generator operation and protection.

In 2015, the unit experienced a fire in the load tunnel due to oil saturated insulation surrounding the load tunnel case. The oil saturated the insulation because a floating seal on number 2 bearing overflowed, which was caused by a failed seal discovered during the unit disassembly.

The unit was disassembled partially during the investigation. Significant wear was found, as expected for a unit of this age, but the unit was deemed safe to run and was returned to normal service.

Preventive maintenance and corrective maintenance is provided by the Clark Station maintenance staff on an as-needed basis.

3.2 Environmental Considerations

Clark 4 is currently in compliance with all environmental agency issued permits and associated limits. No other specific environmental regulations are known at this time that would directly impact the operations of Clark 4.

There are no continuous emission monitoring system (CEMS) required or installed on Clark 4. Clark 4 is not regulated under US EPA 40 CFR Part 60 or 40 CFR Part 75. The unit pre-dates the combustion turbine New Source Performance Standards and the acid rain regulations.

On April 30, 2018, the Environmental Protection Agency (EPA) released a prepublication designation of the Las Vegas Valley as nonattainment with the 2015 National Ambient Air Quality Standard for ozone. This designation will trigger the Clark County Department of Air Quality to take steps to reduce ozone pollution to bring the area into attainment with the standard. No impact on Clark 4 is currently anticipated as the agency's actions are expected to have the most impact on new construction, not existing facilities.

3.3 Infrastructure Considerations

Infrastructure for a unit includes all those support systems that allow a unit to generate and deliver power to the customer. They include land, roads, railways, fuel supply, water supply, transmission access and other features.

The LSAP focuses on current and forecasted changes to the infrastructure elements. There are contracts on many of these infrastructure components and at any time during the life span of the unit, the renewal, expiration or negotiation of these contracts may result in impacts to the economic viability of the unit. Similarly, market conditions are associated with some infrastructure components, with fuel being a prime example.

Clark 4 is connected to Nevada Power's 69 kV transmission system, inside the Las Vegas Valley. There are currently no infrastructure concerns for Clark 4.

4.0 OPTION DEVELOPMENT

The alternatives identified for the future utilization of Clark 4 represent different options that would allow safe and reliable operation of the unit in accordance with environmental regulations.

Since Clark 4 is a peaking unit and Nevada Power is operating at a capacity deficit, no early retirement option was identified.

4.1 Base Case, Retire Clark 4 on Schedule December 31, 2020

This base case assumes that Clark 4 will operate until the eve of December 31, 2020, as planned. This alternative does not include any significant investment in capital for the remaining life of the unit, other than normal turbine maintenance based on operating hours and unit starts. The unit can be expected to continue operating on an as-needed basis to support the transmission grid as necessary in addition to providing energy until its retirement. At retirement on December 31, 2020, Nevada Power would retire the unit and begin decommissioning and demolition of the unit.

4.2 Option A – Extend operation to 2030

This alternative assumes that Clark 4 will operate until the eve of December 31, 2030. This alternative does not include any significant investment in capital for the remaining life of the unit, other than normal turbine maintenance based on operating hours and unit starts. The unit can be expected to continue operating on an as-needed basis to support the transmission grid as necessary in addition to providing energy until its retirement. At retirement on December 31, 2030 Nevada Power would retire its interests in the unit and begin decommissioning and demolition of the unit.

5.0 PLANNING ASSUMPTIONS

The following planning assumptions are used in the ProMod analysis and are used in Nevada Power's business planning.

5.1 Labor

No specific labor is assigned to Clark 4. The Clark Station operations and maintenance staff supports this units along with the other units at the site.

5.2 Expected Operations Strategy

Clark 4 will continue to be a summer run-only asset and will be made available between the months of May and October of each year. During the winter months the unit will be placed in reserve shutdown status.

6.0 OPTION ANALYSIS

6.1 Economic Analysis

As described in the sections above, Clark 4 is expected to have a rather low capacity factor (approximately 0.8 percent) for the remainder of its operating life. Since it is difficult to predict when the unit will operate, the energy value of the unit will be ignored for this analysis. Instead, the analysis will evaluate the capacity value of Clark 4.

Currently, Nevada Power relies on the market to provide a portion of its capacity needs. When Clark 4 retires, its capacity must be replaced – either by another unit or by acquiring even more capacity from the market. This analysis will compare the fixed cost of continuing the operation of Clark 4 to the end of 2030 with the cost of purchasing an equivalent amount of capacity from the market for the same time period.

Figure 4– Economic Analysis Results

	Market Capacity Price ($/kW-yr)	Clark 4 Dependable Capacity (kW)	Cost to replace Clark 4 Capacity ($/yr)	Fixed Operating Cost of Clark 4 ($/yr)	Saving from continued operation of Clark 4
2021	$67.72	54,000	$ 3,656,896	$ 73,496	$3,583,400
2022	$70.84	54,000	$ 3,825,361	$ 74,966	$3,750,395
2023	$76.67	54,000	$ 4,140,267	$ 76,465	$4,063,802
2024	$79.32	54,000	$ 4,283,352	$ 77,994	$4,205,358
2025	$77.63	54,000	$ 4,191,755	$ 79,554	$4,112,201
2026	$76.95	54,000	$ 4,155,216	$ 81,145	$4,074,071
2027	$77.78	54,000	$ 4,200,311	$ 82,768	$4,117,542
2028	$81.58	54,000	$ 4,405,459	$ 84,423	$4,321,035
2029	$85.95	54,000	$ 4,641,411	$ 86,112	$4,555,299
2030	$90.00	54,000	$ 4,859,996	$ 87,834	$4,772,162

The table shows continued operation of Clark 4 saves between $3.5 and $4.7 million per year. The unit enjoys significant capacity value even though it has little energy value.

7.0 LSAP RETIREMENT DATE RECOMMENDATION

The recommendation of this LSAP is to plan for the continued operation of the Clark 4 for an additional 10 years. No extraordinary capital investments are required or expected

for the continued operation of Clark 4 through 2030. The present worth revenue requirement analysis shows that continued operation of the unit is the most economic management of the asset. Continued operation of the unit provides a ready capacity and energy resource for Nevada Power's system and reduces the capacity deficit at peak, compared to retiring the unit. Though there are no other known approved or pending environmental regulations that would materially affect Clark 4, the Company currently believes there would be a high level of uncertainty forecasting environmental capital requirements to operate these units beyond 2030, due to its age at that time of 57 years. Nevada Power recommends modifying the depreciation planning retirement date for Clark 4 to reflect another 10 years of available operation and setting that date as 2030.

GEN-4B

Life Span Analysis Process

Clark Mountain (Tracy), Peaking Unit 3 & Unit 4 County, Nevada

2018 Update

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1.0 EXECUTIVE SUMMARY

The recommendation of this Life Span Analysis Process ("LSAP") is to plan for the continued operation of the Clark Mountain Unit 3 & 4 (the "Units") through 2034. This recommendation would result in continuing the operation of these Units for an additional 10 years beyond their currently assigned retirement date. This recommendation is based primarily on the following factors: 1) there are no other known approved or pending environmental regulations that would materially affect these Units, and 2) these Units are currently operating reliably and are expected to continue to operate in a manner similar to their historic operation. The Tracy Station maintenance team conducts annual borescope inspections of the Units to monitor the condition of the turbine components. Repairs are made as necessary and planned maintenance outages are taken based on the Original Equipment Manufacturer, General Electric's ("GE"), recommended intervals. Based on these inspections and repairs, these units are in good working condition and are expected to meet their expected mode of operation in the future. Based on the reviews that were completed in developing this LSAP, Sierra recommends changing the planning retirement date for these Units to 2034.

2.0 UNIT DESCRIPTIONS

The Units (also known as Tracy Peakers 3 and 4) are located at the Tracy Generating Station, 35 miles east of Reno. The operations and maintenance staff at the Tracy Station operate, monitor and maintain these units.

Unit 3 is a GE model 7EA simple cycle combustion turbine ("CT") that is rated for a net dependable summer capacity of 66 MW. Currently, Unit 3 is designed to primarily fire on natural gas, but remains classified as a dual fuel unit. Diesel oil is maintained as a back-up fuel; however, the air permits restrict operation on diesel oil to emergency use only. The unit optimally operates at a nominal full load heat rate of approximately 12,000 BTU/kw-hr. Unit 3 has traditionally operated intermittently as a peaking unit to meet short term demands in Sierra's system. Unit 3 began commercially operating in 1994 and has been operating for the past 23 years and has a projected retirement date of 2024.

Unit 3 is equipped with Dry Low NOx combustors for nitrogen oxide emission control and is also equipped with a Continuous Emissions Monitoring System ("CEMS").

Unit 4 is also a GE model 7EA simple cycle CT that is rated for a net dependable summer capacity of 66 MW. Currently, Unit 4 is designed to primarily fire on natural gas, but remains classified as a dual fuel unit. Diesel oil is maintained as a back-up fuel; however, the air permits restrict operation on diesel oil to emergency use only used as the start-up fuel. The unit optimally operates at a nominal full load heat rate of approximately 12,000 BTU/kw-hr. Unit 4 has traditionally operated intermittently as a peaking unit to meet short term demands in Sierra's system. Unit 4 began commercially operating in 1994 and has been operating for the past 23 years and has a projected depreciation retirement date of 2024.

Unit 4 is equipped with Dry Low NOx combustors for nitrogen oxide emission control and is also equipped with a CEMS.

The Units currently meet all permitted emissions levels.

Figure 2 - Clark Mountain Plant Photo

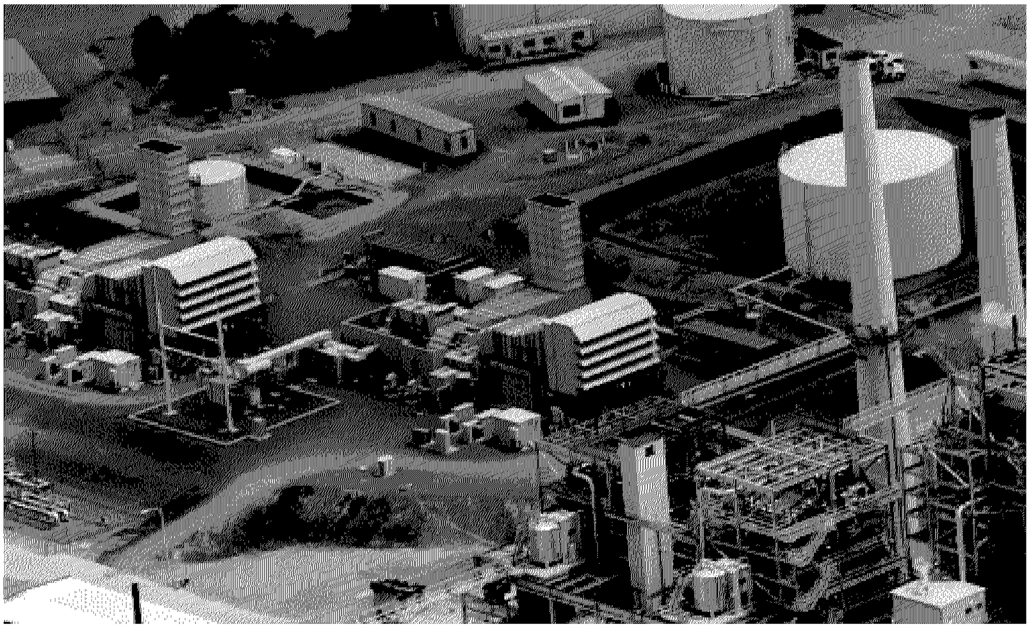
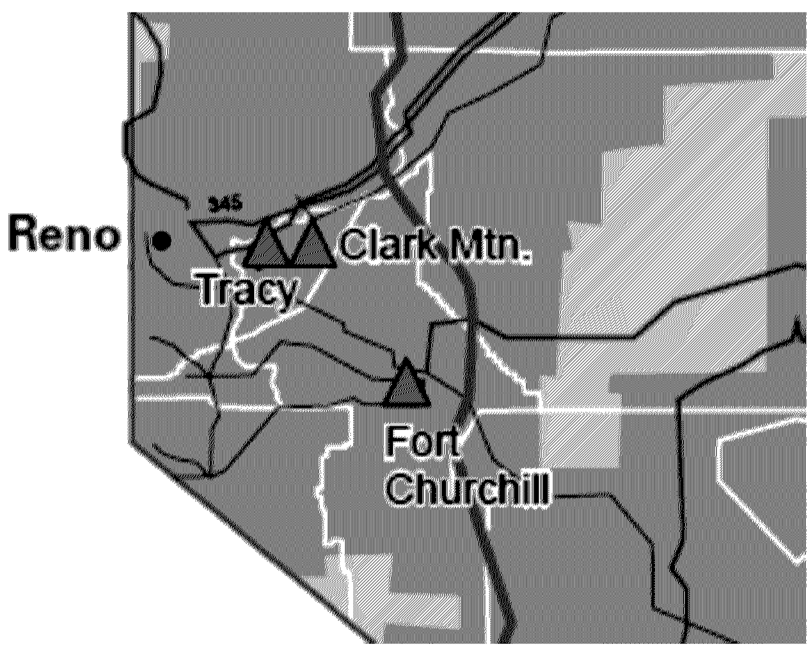


Figure 1 – Tracy/Clark Mountain Plant Location



2.1 Projected Operation

The following table presents the projected operations through 2027. Under the currently projected operations scenario, both Units would continue to operate as peaking units, only operating on an as needed basis.

Figure 3 – Projected Operations – Annual Operating Hours

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Clark Mountain 3	265	320	159	15	22	6	27	1,439	1,909	1,453
Clark Mountain 4	202	279	100	10	20	5	19	1,148	1,540	1,207

The above numbers do not include hours related to dispatch to support the Energy Imbalance Market.

2.2 Projected O&M Budget

The Operations and Maintenance ("O&M") budget for the Clark Mountain Units is based on the variable costs associated with operating the units. The variable costs average $3060/start for each unit and have been reflected in the ProMod modeling of the Clark Mountain Units in the LSAP. The O&M expenses are expressed on a per-start basis since the maintenance intervals are driven by the total number of starts.

2.3 Projected Capital Budget

The current capital budget for the Units is limited to replacement spare parts for each CT. These include combustion components and both stationary and rotating turbine blades. The average annual capital budget for the units is approximately $2540/start. The capital expenses are expressed on a per-start basis since the maintenance intervals are driven by the total number of starts.

3.0 LSAP REASSESSMENT CRITERIA

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. This initial life span is established when the unit is first put in service, or in the case of older units when the LSAP was approved by the Commission,[1] the Reassessment Protocol was used to set an initial life.

After a unit is commissioned and has been in operation, the life span may be reassessed to ensure that the initial Life Span Assessment is still valid or to determine a new plan that is more appropriate for the Unit. The reassessment of unit life span can be undertaken for any of the following **Reassessment Criteria**:

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Environmental Compliance
- Infrastructure
- Significant Event
- Commission Ordered Reassessment.

When a reassessment is undertaken, it can range from cursory to detailed, dependent on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the initial Life Span Assessment. The other end of the spectrum would be a unit entering its planned last decade of operations where operations, maintenance, environmental and infrastructure issues could dictate a detailed review to assess the remaining life span. No matter the nature of the review, the key steps of the **Reassessment Protocol** are as follows:

- Unit Assessment
- Environmental Assessment
- Infrastructure Assessment
- Development of Options
- Options Input to Resource Planning and Financial Analysis
- Final Decision on Life Span Assessment and Implementation Plan

Per the approved LSAP, the following reassessment criteria have been met, triggering an evaluation of the operating life for the Units.

- Unit is within 10 years of last approved retirement date

The following provides a brief explanation of the above trigger and determines the criticality of each trigger for the LSAP analysis.

[1] The Life Span Analysis Process ("LSAP") was approved by the Public Utilities Commission of Nevada in Docket Number 08-08002

Unit Is Within 10 Years of Last Approved Retirement Date

The latest Integrated Resource Plan ("IRP") filing for Sierra shows a retirement date of December 31, 2024, for the Units. Since replacement capacity would take a number of years to permit, design and construct, and investments in replacement units would be required within the next Action Plan period to ensure replacement capacity is available if the Units are planned to retire in 2024.

3.1 Unit Condition Considerations

The most recent maintenance that has been performed on the Units is shown in the table below. The table also shows the total hours and number of starts on the engines at the time of the maintenance.

Unit	Maintenance	Date	Hours	Starts
Clark Mountain 3	Hot Gas Path Inspection	4/2001	21,816	514
Clark Mountain 3	Combustion Inspection	12/2006	28,100	850
Clark Mountain 4	Hot Gas Path Inspection	12/2001	23,850	577
Clark Mountain 4	Combustion Inspection	12/2012	28,334	1209

The next maintenance outage on Clark Mountain Unit 3 is a combustion inspection and is tentatively scheduled for 2018. Clark Mountain Unit 4 is scheduled for a hot gas path inspection in 2019.

The scope and interval for each maintenance activity is shown in the table below. The data in the table is based on recommendations provided by the original equipment manufacturer. Typically, a rotor life assessment is recommended after 200,000 operating hours. Neither unit is forecast to hit this milestone before the scheduled retirement date.

Maintenance and Scope Descriptions

Name	Interval	Duration	Scope
Combustion Inspection	12,000 hrs /450 starts	15 Days	Replacement of combustion hardware
Hot Gas Path	24,000 hrs / 1,200 starts	24 Days	Replacement of combustion hardware and hot gas path hardware. Generator minor.
Major	48,000 hrs /2,400 starts	41 Days	Removal and inspection of rotor. Replacement of combustion and hot gas path hardware. Generator major.

3.2 Environmental Considerations

The Units are currently in compliance with all environmental agency issued permits and their associated regulatory requirements and limitations.

The Tracy Generating Station Title V Air Quality Operating Permit No. AP4911-0194.03 expires on March 16, 2019. All Title V operating permits are renewed on a five-year cycle with permit renewal applications required to be submitted and deemed compete to the regulatory agency at least 240 days (roughly eight months) prior to the expiration of the current permit in order to maintain a permit shield eliminating the risk of current Title V operating permit forfeiture.

The current CEMS system is aging and prudency would suggest replacement and recertification of various major components within the next ten years.

There are no other identified environmental concerns directly contributing to future operation of the Units.

3.3 Infrastructure Considerations

Infrastructure for a unit includes all those support systems that allow a unit to generate and deliver power to the customer. They include land, roads, railways, fuel supply, water supply, transmission access and other features.

The LSAP focuses on current and forecasted changes to the infrastructure elements. There are contracts on many of these infrastructure components and at any time during the life span of the unit, the renewal, expiration or negotiation of these contracts may result in impacts to the economic viability of the unit. Similarly, market conditions are associated with some Infrastructure components, with fuel being a prime example.

There are currently no infrastructure concerns for the Units.

4.0 OPTION DEVELOPMENT

The alternatives identified for the future utilization of the Units represent different options of capital investments in the facility to allow safe and reliable operation of the unit in accordance with environmental regulations.

Since these are peaking units and Sierra is operating at a capacity deficit, no early retirement option was identified.

4.1 Base Case, Retire both Clark Mountain Units December 31, 2024

This alternative assumes that both Units will operate until the eve of December 31, 2024 as planned. This alternative does not include any significant investment in capital for the remaining life of the Units, other than normal turbine maintenance based on operating hours and unit starts. The Units can be expected to continue operating on an as needed basis to support the transmission grid as necessary in addition to providing energy until their retirement. At retirement on December 31, 2024 Sierra would retire its interests in the plant.

4.2 Option A – Extend operation to 2034

This alternative assumes that both of the Units will operate until the eve of December 31, 2034. This alternative does not include any significant investment in capital for the remaining life of the Units, other than normal turbine maintenance based on operating hours and unit starts. The units can be expected to continue operating on an as needed basis to support the transmission grid as necessary in addition to providing energy until their retirement. At retirement on December 31, 2034 Sierra would retire its interests in the plant.

5.0 PLANNING ASSUMPTIONS

The following planning assumptions are used in the ProMod analysis and are used in Sierra's business planning.

5.1 Labor

No change is labor is expected to result from the retirement of the Units. The costs associated with operating and maintaining the Units are primarily variable costs. No incremental labor is associated with operating or maintaining the units.

5.2 Expected Operations Strategy:

The Units are typically dispatched to meet peak loads during the summer and winter months. The units are also used to meet capacity reserve margins throughout the year. This includes operating the units for spinning reserve and maintaining them in standby mode as "quick-start" capacity.

6.0 OPTION ANALYSIS

6.1 Economic Analysis

As described in the sections above, the Units are expected to have a rather low capacity factor (approximately 8.4 percent) for the remainder of their operating life. Since it is difficult to predict when the Units will operate, the energy value of the Units will be ignored for this analysis. Instead, the analysis will evaluate the capacity value of the Units.

Currently, Sierra relies on the market to provide a portion of its capacity needs. When the Units retire, their capacity must be replaced – either by another unit or by acquiring even more capacity from the market. This analysis will compare the fixed cost of continuing the operation of the Units to the end of 2034 with the cost of purchasing an equivalent amount of capacity from the market for the same time period.

Figure 4 – Economic Analysis Results

	Market Capacity Price ($/kW-yr)	Clark Mtn 3&4 Dependable Capacity (kW)	Cost to replace Clark Mtn 3&4 Capacity ($/yr)	Fixed Operating Cost of Clark Mtn 3&4 ($/yr)	Saving from continued operation of Clark Mtn 3&4
2025	$77.63	132,000	$ 10,246,511	$ 348,360	$ 9,898,152
2026	$76.95	132,000	$ 10,157,194	$ 355,327	$ 9,801,867
2027	$77.78	132,000	$ 10,267,426	$ 362,433	$ 9,904,992
2028	$81.58	132,000	$ 10,768,899	$ 369,682	$ 10,399,217
2029	$85.95	132,000	$ 11,345,670	$ 377,076	$ 10,968,595
2030	$90.00	132,000	$ 11,879,990	$ 384,617	$ 11,495,372
2031	$91.01	132,000	$ 12,013,836	$ 392,309	$ 11,621,526
2032	$94.38	132,000	$ 12,457,595	$ 400,156	$ 12,057,439
2033	$97.59	132,000	$ 12,882,423	$ 408,159	$ 12,474,264
2034	$99.34	132,000	$ 13,112,417	$ 416,322	$ 12,696,095

The table shows continued operation of the Units saves between $9.9 and $12.7 million per year. The Units enjoy significant capacity value even though they have little energy value.

7.0 LSAP RETIREMENT DATE RECOMMENDATION

The recommendation of this LSAP is to plan for the continued operation of Units 3 and 4 for an additional 10 years. No extraordinary capital investments are required for the continued operation of the Units through 2034. The present worth revenue requirement analysis shows that continued operation of the Units is the most economic management of the asset. Continued operation of the Units provides a ready capacity and energy resource for Sierra's system and reduces the capacity deficit at peak, compared to retiring the Units. Though there are no other known approved or pending environmental regulations that would materially affect the Units, the Company currently believes there would be a high level of uncertainty forecasting environmental capital requirements to operate these units beyond 2034. In addition, the peaking operation of these Units and their quick start capability will continue support the addition of more intermittent renewable resources supplying Sierra's system. Sierra recommends modifying the planning retirement date for both of the Units to reflect another 10 years of available operation and setting that date as 2034.

GEN-4C

Life Span Analysis Process

Fort Churchill Unit 1
Yerington, Nevada

2018 Update

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1.0 EXECUTIVE SUMMARY

The recommendation of this Life Span Analysis Process ("LSAP") is to plan for the continued operation of Fort Churchill Unit 1 (the "Unit") through 2028. This recommendation would result in continuing the operation of this Unit for an additional three years beyond its currently assigned retirement date. This recommendation is based primarily on the following factors: 1) there are no other known approved or pending environmental regulations that would materially affect the unit, and 2) the unit is currently operating reliably and is expected to continue to operate in a manner similar to its historic operation. The Fort Churchill Generating Station maintenance team continues to inspect and maintain the Unit on a regular basis and repairs are made as necessary and planned maintenance outages are taken based on the Original Equipment Manufacturer recommended intervals and based on good utility practices. Based on these inspections and repairs, the Unit is in good working condition and is expected to meet its expected mode of operation in the future. Based on the reviews that were completed in developing this LSAP, Sierra recommends changing the planning retirement date of the Unit to 2028. This date also coincides with the retirement date of Fort Churchill Unit 2.

2.0 UNIT DESCRIPTIONS

Fort Churchill Station is located 10 miles north of Yerington, Nevada and is owned and operated by Sierra Pacific Power Company d/b/a NV Energy ("Sierra").

Fort Churchill Station consists of two similar units, each rated at 117 MW gross capacity with a net dependable capacity of 113 MW. Currently, both units may fire natural gas. The units optimally operate at an approximate 10,800 BTU/kw-hr heat rate.

The Unit has been in operation for 44 years and has a current approved retirement date of December 2025.

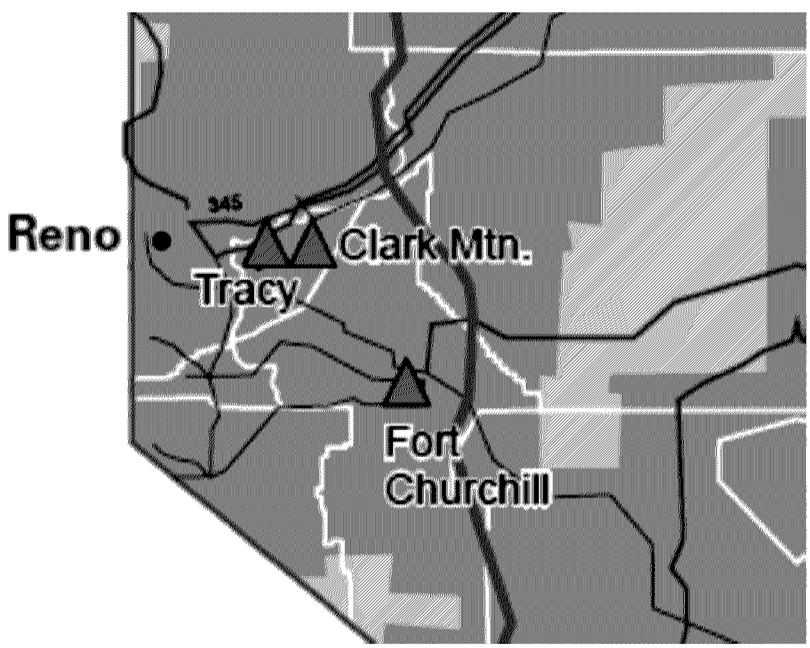
Currently, the Unit has low NOx burners and a new burner control system, and is equipped with a Continuous Emission Monitoring System ("CEMS"), which was upgraded in 2014 with a Windows-based data acquisition system.

Over the past few years, the dispatch of the Unit has been reduced with upgrades to Sierra's transmission system and the installation of a new combined cycle block at Tracy Generating Station. Also, an interconnection to the southern Nevada's transmission system (called the One Nevada Line, or ON-Line) has made low heat rate power from the southern fleet available to the northern system, which has further reduced the power generation demand from Fort Churchill Station. Recent mining and data center developments in the load pocket could reverse this trend requiring additional energy supply from the Unit. Integration of variable renewable generation could require Fort Churchill to run at minimum load to support the reliability of the grid. With these changes in Sierra's transmission and generation system, the Fort Churchill Station, originally designed for base load, has been operating in a seasonal cycling mode.

With the increase of variable renewable energy to the northern grid and the commissioning of the ON-Line transmission interconnection, there is some question as to how the Unit will be dispatched to support load and transmission stability. This uncertainty could dramatically change both the scope and estimates presented in this document.

Figure 1 – Fort Churchill Station

Figure 2 – Fort Churchill Location



2.1 Projected Operation

The following table presents the projected operations through 2027. Under the currently projected operations scenario, both units would continue to operate as peaking units, with primary function to cover summer peak load.

Figure 3 – Projected Operations – Annual Operating Hours

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Ft. Churchill 1	1968	1262	2004	2073	1268	1256	1244	1341	596	504
Ft. Churchill 2	1985	1870	2210	1994	952	979	846	1409	783	729

2.2 Projected O&M Budget

The Operations and Maintenance ("O&M") budget for the Fort Churchill Station currently has a total O&M budget of $5 million dollars per year for both units. This does not include planned outage maintenance. .

2.3 Projected Capital Budget

The budget for the plant is limited by the Energy Choice Initiative guidance memo. The current planned capital budget for the Fort Churchill Station is limited to replacement of batteries in 2026 due to life expectancy of the batteries. The total planned capital expense for this site is $150,000.00 through the 2028 retirement of Fort Churchill Unit 2. The actual dispatch of the units could alter this budget, especially planned outage work.

3.0 LSAP REASSESSMENT CRITERIA

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. This initial life span is established when the unit is first put in service, or in the case of older units when the LSAP was approved by the Commission,[1] the Reassessment Protocol was used to set an initial life.

After a unit is commissioned and has been in operation, the life span may be reassessed to ensure that the Initial Life Span Assessment is still valid or to determine a new plan that is more appropriate for the Unit. The reassessment of unit life span can be undertaken for any of the following **Reassessment Criteria**:

[1] The Life Span Analysis Process was approved by the Commission in Docket No. 08-08002

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Environmental Compliance
- Infrastructure
- Significant Event
- Commission Ordered Reassessment.

When a reassessment is undertaken, it can range from cursory to detailed, dependent on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the Initial Life Span Assessment. The other end of the spectrum would be a Unit entering its planned last decade of operations where operations, maintenance, environmental and infrastructure issues could dictate a detailed review to assess the remaining life span. No matter the nature of the review, the key steps of the **Reassessment Protocol** are as follows:

- Unit Assessment
- Environmental Assessment
- Infrastructure Assessment
- Development of Options
- Options Input to Resource Planning and Financial Analysis
- Final Decision on Life Span Assessment and Implementation Plan

Per the approved LSAP, the following reassessment criteria have been met, triggering an evaluation of the operating life for the Unit:

- Unit is within 10 years of last approved retirement date

The following provides a brief explanation of the above trigger and determines the criticality of each trigger for the LSAP analysis.

Unit Is Within 10 Years of Last Approved Retirement Date

The latest Integrated Resource Plan filing for Sierra shows a retirement date of December 31, 2025 for the Unit. Since replacement capacity would take a number of years to permit, design and construct, and investments in replacement units would be required within the next Action Plan period to ensure replacement capacity is available if the units are planned to retire in 2025.

3.1 Unit Condition Considerations

The Unit is 44 years old and nearing the end of its design life. The Unit was designed to be a base loaded unit. The Unit is within 10 years of the current Commission approved retirement date of December 31, 2025.

The last overhauls on the Unit were completed in 2006 and 2012. A steam turbine major

was performed in 2006. The turbine is in good condition. The boiler life assessment completed by Aptech in 2006 indicates that that the boiler is in good condition. The boiler feed pumps and condensate pumps were overhauled in 2006. The Generator Step-Up Transformer was replaced in 2009, and a new static exciter was installed on the unit.

To meet Best Available Retrofit Technology environmental regulations, the Unit was retrofitted with new burner technology, new burner controls and flue gas recirculation in 2014.

Sierra believes the Unit is in good working condition and is currently being used to serve load and is ready to operate on an as-needed basis.

3.2 Environmental Considerations

The Unit is currently in compliance with all environmental agency issued permits and their associated regulatory requirements and limitations.

The Fort Churchill Station Title V Air Quality Operating Permit No. AP4911-0091.03 is currently in the renewal process, and with no action by the regulatory agency in issuing a draft renewal permit, a new renewal application will be submitted to the regulatory agency in 2019. All Title V operating permits are renewed on a five-year cycle with permit renewal applications required to be submitted and deemed compete to the regulatory agency at least 240 days (roughly eight months) prior to the expiration of the current permit in order to maintain a permit shield eliminating the risk of current Title V operating permit forfeiture.

The Fort Churchill Station recently completed a dam safety hazard analysis for the cooling pond to determine the hazard rating. e.g., low hazard or significant hazard. The hazard analysis was submitted to the State of Nevada, Division of Water Resources ("NDWR"), which included a modeled inundation map and the recommendation of a low hazard. If NDWR agrees with the recommendation, no further evaluation is needed. However, if NDWR refutes Sierra's recommendation and determines the cooling pond should carry a significant hazard rating, Sierra will be required to develop an Emergency Acton Plan and there will be an associated cost to develop this plan.

There are no other identified environmental concerns directly contributing to future operation of the Unit.

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3.3 Infrastructure Considerations

Infrastructure for a unit includes all those support systems that allow a unit to generate and deliver power to the customer. They include land, roads, railways, fuel supply, water supply, transmission access and other features.

The LSAP focuses on current and forecasted changes to the infrastructure elements.

There are contracts on many of these infrastructure components and at any time during the life span of the unit, the renewal, expiration or negotiation of these contracts may result in impacts to the economic viability of the unit. Similarly, market conditions are associated with some infrastructure components, with fuel being a prime example.

There are currently no infrastructure concerns for the Unit.

4.0 OPTION DEVELOPMENT

The alternatives identified for the future utilization of the Unit represents different options of capital investments in the facility to allow safe and reliable operation of the unit in accordance with environmental regulations.

Since Sierra is operating at a capacity deficit, no early retirement option was identified.

4.1 Base Case, Retire Fort Churchill Unit 1 December 31, 2025

This alternative assumes that the Unit will operate until the eve of December 31, 2025 as planned. This alternative does not include any significant investment in capital for the remaining life of the Unit, other than normal turbine maintenance based on operating hours and unit starts. The Unit can be expected to continue operating on an as needed basis to support the transmission grid as necessary in addition to providing energy until its retirement. At retirement on December 31, 2025 Sierra would retire its interests in the plant.

4.2 Option A – Extend operation to 2028

This alternative assumes that the Unit will operate until the eve of December 31, 2028. This alternative does not include any significant investment in capital for the remaining life of the Unit, other than normal turbine maintenance based on operating hours and unit starts. The Unit can be expected to continue operating on an as needed basis to support the transmission grid as necessary in addition to providing energy until their retirement. At retirement on December 31, 2028, Sierra would retire the plant.

5.0 PLANNING ASSUMPTIONS

The following planning assumptions are used in the ProMod analysis and are used in Sierra's business planning.

5.1 Labor

No change in labor is expected to result from the change in retirement date of the Unit because Fort Churchill Unit 2 is expected to continue operating until 2028. The incremental costs associated with operating and maintaining the Unit is primarily variable costs, since fixed plant costs are also associated with Forth Churchill Unit 2. No incremental labor is associated with operating or maintaining the Unit. Changing operational demands could change this assumption.

5.2 Expected Operations Strategy:

The Unit is typically dispatched to meet loads during the summer The Unit is also used to meet capacity reserve margins throughout the year. This includes operating the Unit to support load requirements in the Carson City area.

6.0 OPTION ANALYSIS

6.1 Economic Analysis

Currently, Sierra relies on the market to provide a portion of its capacity needs. When the Unit retires, its capacity must be replaced – either by another unit or by acquiring even more capacity from the market. This analysis will compare the fixed cost of continuing the operation of the Unit to the end of 2028 with the cost of purchasing an equivalent amount of capacity from the market for the same time period. The Unit is expected to have a capacity factor of approximately 17 percent, so the analysis will also subtract the fuel costs of continuing operation of the Unit to the end of 2028.

Figure 4 – Economic Analysis Results

	Market Capacity Price ($/kW-yr)	Ft. Churchill 1 Dependable Capacity (kW)	Cost to replace Ft. Churchill 1 Capacity ($/yr)	Fixed Operating Cost of Ft. Churchill 1 ($/yr)	Fuel Cost of Ft. Churchill 1 ($/yr)	Saving from continued operation of Ft. Churchill 1
2026	$76.95	113,000	$ 8,695,174	$ 3,147,753	$1,589,663	$ 3,957,757
2027	$77.78	113,000	$ 8,789,539	$ 3,210,708	$1,483,679	$ 4,095,151
2028	$81.58	113,000	$ 9,218,831	$ 3,274,922	$1,306,596	$ 4,637,312

The table shows continued operation of the Unit saves between $3.9 and $4.7 million per year.

7.0 LSAP RETIREMENT DATE RECOMMENDATION

The recommendation of this LSAP is to plan for the continued operation of the Unit for an additional three years. No extraordinary capital investments are required for the continued operation of the unit through 2028. The present worth revenue requirement analysis shows that continued operation of the Unit is the most economic management of the asset. Continued operation of the Unit provides a ready capacity and energy resource for Sierra's system and reduces the capacity deficit at peak, compared to retiring the Unit. Though there are no other known approved or pending environmental regulations that would materially affect the Fort Churchill Station, the Company currently believes there would be a high level of uncertainty forecasting environmental capital requirements to operate these units beyond 2028. Sierra recommends modifying the depreciation planning retirement date for the Unit to reflect another three years of

available operation and setting that date as 2028.

APPENDIX A

FINAL ORDER NO. 33771

Idaho Public Utilities Commission

Case Number IPC-E-16-24

APPENDIX B

CONFIDENTIAL TERM SHEET

REDACTED

GEN-4D

Life Span Analysis Process

Harry Allen Unit 3
Clark County, Nevada

2018 Update

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1.0 EXECUTIVE SUMMARY

The recommendation of this Life Span Analysis Process ("LSAP") is to plan for the continued operation of the Harry Allen Unit 3 (the "Unit") through 2035. This recommendation would result in continuing the operation of this Unit for an additional 10 years beyond its currently assigned retirement date. This recommendation is based primarily on the following factors: 1) there are no other known approved or pending environmental regulations that would materially affect the unit, and 2) the unit is currently operating reliably and is expected to continue to operate in a manner similar to its historic operation. The Harry Allen Station maintenance team conducts annual borescope inspections of the Unit to monitor the condition of the turbine components. Repairs are made as necessary and planned maintenance outages are taken based on the Original Equipment Manufacturer ("OEM"), General Electric's ("GE"), recommended intervals and projected cost benefit versus risk. Based on these inspections and repairs, the Unit is in good working condition and is expected to meet its expected mode of operation in the future. Based on the reviews that were completed in developing this LSAP, Nevada Power Company ("Nevada Power") recommends changing the planning retirement date to 2035. This life is consistent with the lives recommended for the other GE 7EA units in Nevada Power's and Sierra Pacific Power Company's ("Sierra") systems.

2.0 UNIT DESCRIPTIONS

The Unit is located on the Harry Allen Generating Station, 25 miles north of Las Vegas in the Apex area. The operations and maintenance staff at the Harry Allen Station operate, monitor and maintain these units.

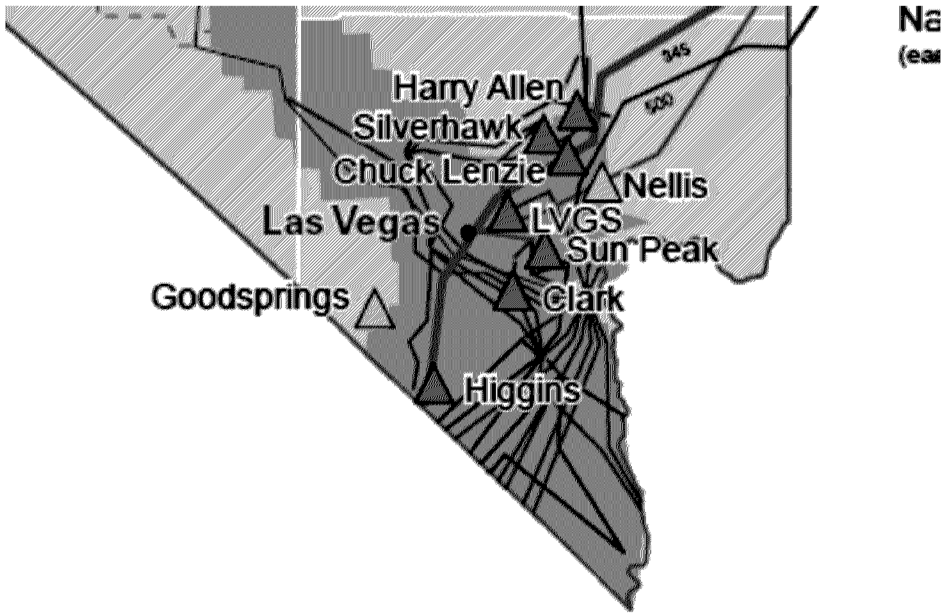
The Unit is a GE model 7EA simple cycle combustion turbine ("CT") that is rated for a net dependable summer capacity of 72 MW. Currently, the Unit is designed to fire on natural gas. The Unit optimally operates at an approximate 10,480 BTU/kw-hr heat rate. The Unit has traditionally operated intermittently as a peaking unit to meet short term demands in Nevada Power's system. The Unit began commercially operating in 1995 and has been operating for the past 22 years and has a projected retirement date of 2025.

The Unit is equipped with Low NOx burners for nitrogen oxide emission control. The Unit is also equipped with a Continuous Emissions Monitoring System ("CEMS").

The Unit currently meets all permitted emissions levels.

Figure 1 – Harry Allen Unit 3

Figure 2 – Harry Allen Generating Station Location



2.1 Projected Operation

The following table presents the projected operations through 2027.

Figure 3 – Projected Unit Operations

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MWhrs	17669	34921	7402	4286	4883	3228	2409	2538	36400	20542
Capacity Factor	2.80%	5.54%	1.17%	0.68%	0.77%	0.51%	0.38%	0.40%	5.77%	3.26%

The actual runtime of the Unit will be dependent on the EIM. If the Unit continues to be offered into the market, the runtime will likely be higher than the projections above.

2.2 Projected O&M Budget

The Operations and Maintenance ("O&M") budget for the Clark Mountain Units is

based on the variable costs associated with operating the units. The variable costs average $3060/start for each unit and have been reflected in the ProMod modeling of the Clark Mountain Units in the LSAP. The O&M expenses are expressed on a per-start basis since the maintenance intervals are driven by the total number of starts.

2.3 Projected Capital Budget

The current capital budgets only include normal capital replacement of damaged or worn out equipment. No major capital expenditures are expected for the Unit except for CEMs analyzer replacements in 2022. If the Unit continues to be offered into the EIM, an increase in capital expenditures for wear and tear will likely be required.

3.0 LSAP REASSESSMENT CRITERIA

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. This initial life span is established when the unit is first put in service, or in the case of older units when the LSAP was approved by the PUCN,[1] the Reassessment Protocol was used to set an initial life.

After a Unit is commissioned and has been in operation, the life span may be reassessed to ensure that the Initial Life Span Assessment is still valid or to determine a new plan that is more appropriate for the unit. The reassessment of unit life span can be undertaken for any of the following **Reassessment Criteria**:

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Environmental Compliance
- Infrastructure
- Significant Event
- Commission Ordered Reassessment.

When a reassessment is undertaken, it can range from cursory to detailed, dependent on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the Initial Life Span Assessment. The other end of the spectrum would be a unit entering its planned last decade of operations where operations, maintenance, environmental and infrastructure issues could dictate a detailed review to assess the remaining life span. No matter the nature of the review, the key steps of the **Reassessment Protocol** are as follows:

- Unit Assessment
- Environmental Assessment

[1] The Life Span Analysis Process was approved by the Commission in Docket No. 08-08002

- Infrastructure Assessment
- Development of Options
- Options Input to Resource Planning and Financial Analysis
- Final Decision on Life Span Assessment and Implementation Plan

Per the approved LSAP, the following reassessment criteria have been met, triggering an evaluation of the operating life for the Unit.

- Unit is within 10 years of last approved retirement date

The following provides a brief explanation of the above trigger and determines the criticality of each trigger for the LSAP analysis.

Unit Is Within 10 Years of Last Approved Retirement Date

The latest Integrated Resource Plan filing for Nevada Power shows a retirement date of December 31, 2025, for the Unit. This was based on a typical assumed life of a peaking combustion turbine of 30 years. Since replacement capacity would take a number of years to permit, design and construct, and investments in replacement units would be required within the next Action Plan period to ensure replacement capacity is available if the Unit is planned to retire in 2025, it is prudent to review this retirement date at this time.

3.1 Unit Condition Considerations

The Unit began commercial operation October 1995. The Unit was originally designed to use natural gas as the primary fuel with distillate as back up. The combustion turbine is equipped with Dry Low NOx ("DLN") combustor and an evaporator cooler is provided to cool inlet air to the combustion turbine. During the February 2005 Hot Gas Path Inspection ("HGP") the fuel oil piping and water injection piping was removed from the inside of the turbine compartment. The Unit continues with natural gas only.

The February 2005 HGP was completed per GE's routine maintenance recommendations, work scope included refurbish or replace fuel nozzles, combustion liners, crossfire tubes, transition pieces. During the HGP, 1st stage shroud blocks were repaired and reinstalled and the 1st stage nozzle segments were repaired and reinstalled. All hot gas path components were repaired or refurbished per OEM standards.

A forced outage event occurred in April 2007 on the Unit when the 2nd stage nozzle-edge seal came loose damaging the row 17 blades along with associated compressor discharge casing. The OEM replaced the row 17 blades, completed shroud, liner and bearing repairs, extensive offsite machining was completed on the compressor discharge casing.

In December 2010, during the restoration of a routine fire test, the generator dampener was not restored to operational position. When the Unit was started, the generator was

exposed to extremely high operating temps. Extensive electrical testing was completed along with HI-pot at 1.5 times the rated DC voltage, all electrical tests passed. Upon startup a partial discharge test of the stator windings was completed that indicated Very High partial discharge. The plant maintenance staff continues to monitor the condition of the windings and will address if conditions dictate.

In November 2013, a "Fast Start" upgrade was installed on the Unit, which gives Harry Allen's operations staff the flexibility to bring the Unit to full load in 10 minutes.

Since commissioning, regular/routine borescopes have played a significant role in the maintenance and care of the Unit. A combustion inspection is planned and scheduled for 2019.

3.2 Environmental Considerations

The Unit is currently in compliance with all environmental agency issued permits and associated emissions limits. No other specific environmental regulations are known at this time that would directly impact the operations of the Unit. However, the carbon monoxide (CO) emissions have been increasing over the years. It is believed that the Unit needs a combustion inspection to resolve the CO issue. The combustion inspection is scheduled for 2018.

3.3 Infrastructure Considerations

Infrastructure for a unit includes all those support systems that allow a unit to generate and deliver power to the customer. They include land, roads, railways, fuel supply, water supply, transmission access and other features.

The LSAP focuses on current and forecasted changes to the infrastructure elements. There are contracts on many of these infrastructure components and at any time during the life span of the unit, the renewal, expiration or negotiation of these contracts may result in impacts to the economic viability of the unit. Similarly, market conditions are associated with some Infrastructure components, with fuel being a prime example.

There are currently no infrastructure concerns for the Unit.

4.0 OPTION DEVELOPMENT

The alternatives identified for the future utilization of the Unit represent different options of capital investments in the facility to allow safe and reliable operation of the Unit in accordance with environmental regulations.

Since this is a peaking unit and Nevada Power is operating at a capacity deficit, no early retirement option was identified. Continuing operations for an additional 10 years was chosen for the Unit, because it is consistent with the lives recommended for the other GE 7EA units in Nevada Power's and Sierra's systems.

4.1 Base Case, Retire Harry Allen Unit 3 on December 31, 2025

This base case assumes that the Unit operates until the eve of December 31, 2025 as planned. This alternative does not include any significant investment in capital for the remaining life of the Unit, other than normal turbine maintenance based on operating hours and unit starts. At retirement on December 31, 2025, Nevada Power would retire its interests in the Unit and begin decommissioning and demolition.

4.2 Option A – Extend operation to 2035

This alternative assumes that the Unit operates until the eve of December 31, 2035 as proposed. This alternative does not include any significant investment in capital for the remaining life of the Unit, other than normal turbine maintenance based on operating hours and unit starts. At retirement on December 31, 2035, Nevada Power would retire its interests in the Unit and begin decommissioning and demolition.

5.0 PLANNING ASSUMPTIONS

The following planning assumptions are used in the ProMod analysis and are used in Nevada Power's business planning.

5.1 Labor

The Unit has historically required maintenance personnel's time during startups due to the age of the equipment. However, this labor support is provided from existing Harry Allen Generating Station personnel and would not increase the station's labor staffing requirements.

5.2 Expected Operations Strategy:

The unit will dispatch consistent with its historical dispatch. EIM may affect the starts and run times as well.

6.0 OPTION ANALYSIS

6.1 Economic Analysis

As described in the sections above, the Unit is expected to have a rather low capacity factor for the remainder of its operating life. Since it is difficult to predict when the Unit will operate, the energy value of the Unit is not included in this analysis. Instead, the analysis will evaluate the capacity value of the Unit.

Currently, Nevada Power relies on the market to provide a portion of its capacity needs. When the Unit retires, its capacity must be replace – either by another unit or by acquiring even more capacity from the market. This analysis will compare the fixed cost of continuing the operation of the Unit to the end of 2035 with the cost of purchasing an equivalent amount of capacity from the market for the same time period.

Figure 4 – Economic Analysis Results

	Market Capacity Price ($/kW-yr)	Harry Allen Unit 3 Dependable Capacity (kW)	Cost to replace Harry Allen Unit 3 Capacity ($/yr)	Fixed Operating Cost of Harry Allen Unit 3 ($/yr)	Saving from continued operation of Harry Allen 3
2026	93.77	72,000	$ 6,751,440	$ 245,736	$ 6,505,704
2027	98.37	72,000	$ 7,082,640	$ 250,650	$ 6,831,990
2028	104.05	72,000	$ 7,491,600	$ 255,663	$ 7,235,937
2029	105.88	72,000	$ 7,623,360	$ 260,777	$ 7,362,583
2030	106.14	72,000	$ 7,642,080	$ 265,992	$ 7,376,088
2031	108.44	72,000	$ 7,807,680	$ 271,312	$ 7,536,368
2032	108.22	72,000	$ 7,791,840	$ 276,738	$ 7,515,102
2033	110.06	72,000	$ 7,924,320	$ 282,273	$ 7,642,047
2034	115.63	72,000	$ 8,325,360	$ 287,918	$ 8,037,442
2035	120.37	72,000	$ 8,666,640	$ 293,677	$ 8,372,963

The table shows continued operation of the Unit saves between $6 and $8.4 million per year. The Unit enjoys significant capacity value even if it little energy value.

6.2 Risk Discussion

The retirement of the Unit on its current 2025 date will increase the Company's open position and subject it to additional market risk. With little investment requirements and high economic benefits of continuing to operate the Unit, market risk will be reduced

by continuing operations the additional 10 years.

7.0 LSAP RETIREMENT DATE RECOMMENDATION

The recommendation of this LSAP is to plan for the continued operation of the Unit for an additional 10years. No extraordinary capital investments are required for the continued operation of the Unit through 2035. The present worth revenue requirement analysis shows that continued operation of the Unit is the most economic management of the asset. Continued operation of the Unit provides a ready capacity and energy resource for Nevada Power's system and reduces the capacity deficit at peak, compared to retiring the Unit on schedule. Though there are no other known approved or pending environmental regulations that would materially affect the Unit , the Company currently believes there would be a high level of uncertainty forecasting environmental and capital requirements to operate the Unit beyond 2035. In addition, the peaking operation of this Unit and its quick start capability will continue support the addition of more intermittent renewable resources supplying Nevada Power's system. Nevada Power recommends modifying the planning retirement date for the Unit to reflect another 10 years of available operation and setting the planning retirement date as 2035.

GEN-4E

Life Span Analysis Process

Sun Peak Units 3, 4 & 5
Clark County, Nevada

2018 Update

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1.0 EXECUTIVE SUMMARY

The recommendation of this Life Span Analysis Process ("LSAP") is to plan for the continued operation of the Sun Peak Units 3, 4 and 5 (the "Units") through 2031. This recommendation would result in continuing the operation of these Units for an additional five years beyond their currently assigned retirement date. This recommendation is based primarily on the following factors: 1) there are no other known approved or pending environmental regulations that would materially affect these Units, and 2) these units are currently operating reliably and are expected to continue to operate in a manner similar to their historic operation. The Clark Station maintenance team conducts annual borescope inspections of the Units to monitor the condition of the turbine components. Repairs are made as necessary and planned maintenance outages are taken based on the Original Equipment Manufacturer, General Electric's ("GE"), recommended intervals. Based on these inspections and repairs, these Units are in good working condition and are expected to meet their expected mode of operation in the future. Based on the reviews that were completed in developing this LSAP, Nevada Power recommends changing the planning retirement date to 2031. This recommendation is consistent with the lives for the other GE 7EA units in Nevada Power Company's ("Nevada Power") and Sierra Pacific Power Company's ("Sierra") systems.

2.0 UNIT DESCRIPTIONS

The Units are located at the site of the previous Sunrise Station on the east side of the Las Vegas valley. The operations and maintenance staff at Clark Station operate, monitor and maintain these units, with a dedicated operations staff at the Sun Peak Station.

Sun Peak Unit 3 ("Unit 3") is a GE model 7EA simple cycle combustion turbine ("CT") that is rated for a net dependable summer capacity of 72 MW. Currently, Unit 3 is designed to primarily fire on natural gas, but remains classified as a dual fuel unit. Diesel oil is maintained as a back-up fuel. The unit optimally operates at an approximate 10,350 BTU/kw-hr heat rate. Unit 3 has traditionally operated intermittently as a peaking unit to meet short term demands in Nevada Power's system, but was operated and maintained by the Sun Peak Limited Partnership, until Nevada Power's purchase of the unit in 2016. Unit 3 began commercially operating in 1991 and has been operating for the past 27 years and has a projected depreciation retirement date of 2026.

Unit 3 is equipped with a Continuous Emissions Monitoring System ("CEMS").

SunPeak Unit 4 ("Unit 4") is a GE model 7EA simple CT that is rated for a net dependable summer capacity of 72 MW. Currently, Unit 4 is designed to primarily fire on natural gas, but remains classified as a dual fuel unit. Diesel oil is maintained as a back-up fuel. The unit optimally operates at an approximate 10,350 BTU/kw-hr heat rate. Unit 4 has traditionally operated intermittently as a peaking unit to meet short-term demands in Nevada Power's system, but was operated and maintained by the Sun Peak Limited Partnership, until Nevada Power's purchase of the unit in 2016. Unit 4 began commercially operating in 1991 and has been operating for the past 27 years and has a projected depreciation retirement date of 2026.

Unit 4 is equipped with a CEMS.

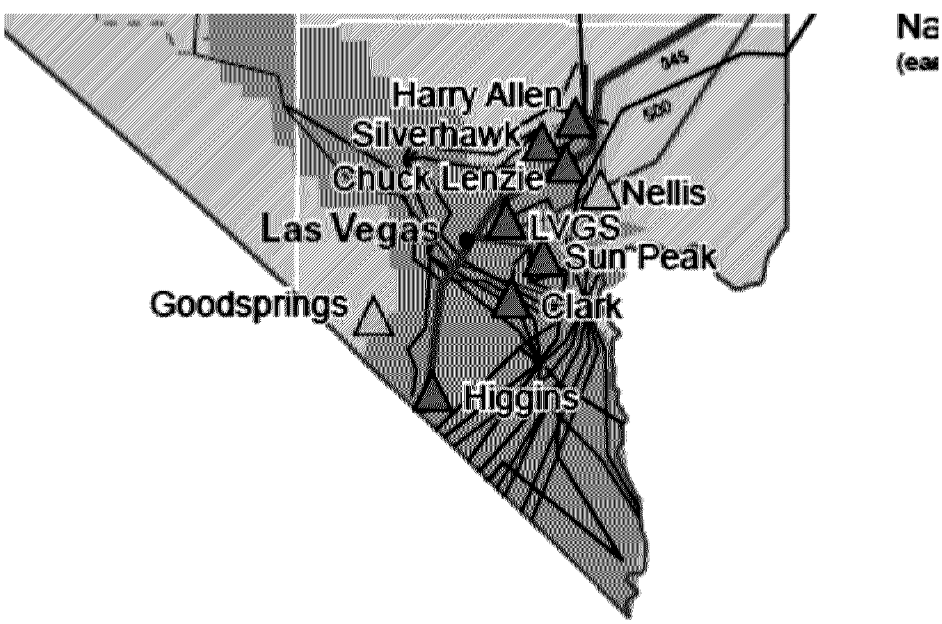
SunPeak Unit 5 ("Unit 5") is a GE model 7EA simple CT that is rated for a net dependable summer capacity of 72 MW. Currently, Unit 5 is designed to primarily fire on natural gas, but remains classified as a dual fuel unit. Diesel oil is maintained as a back-up fuel. The unit optimally operates at an approximate 10,350 BTU/kw-hr heat rate. Unit 5 has traditionally operated intermittently as a peaking unit to meet short term demands in Nevada Power's system, but was operated and maintained by the Sun Peak Limited Partnership, until Nevada Power's purchase of the unit in 2016. Unit 5 began commercially operating in 1991 and has been operating for the past 27 years and has a projected depreciation retirement date of 2026.

Unit 5 is equipped with a CEMS.

All of the Units currently meet all permitted emissions levels.

Figure 1 – Sun Peak Generating Units

Figure 2 – Sun Peak Station Location



2.1 Projected Operation

The following table presents the projected operations of the Units through 2027. Under the currently projected operations scenario, the Units would continue to operate as peaking units, only operating on an as needed basis.

Figure 3 – Projected Operations – Annual Operating Hours

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Sun Peak Unit 3	342	297	214	129	142	20	14	16	22	0
Sun Peak Unit 4	305	299	206	113	134	19	12	15	21	0
Sun Peak Unit 5	309	261	166	100	117	18	12	12	17	0

2.2 Projected O&M Budget

With continued summer-only operations, the Operations and Maintenance ("O&M") budget for 2018 is projected to be $1.7 million. The projected O&M budgets for 2019 through 2025 averages $1.9 million per year.

2.3 Projected Capital Budget

The current capital budgets are based on the Energy Choice Initiative memo and only includes normal capital replacement of damaged or worn out equipment. Only one capital addition expected for the Units is prior to 2025. The Excitation Controls project is currently planned for 2019 with a remaining cost of approximately $300,000.

3.0 LSAP REASSESSMENT CRITERIA

The LSAP provides an initial life span estimate based on a unit's design and intended mode of operation. This initial life span is established when the unit is first put in service, or in the case of older units when the LSAP was approved by the Commission,[1] the Reassessment Protocol was used to set an initial life.

After a unit is commissioned and has been in operation, the life span may be reassessed to ensure that the Initial Life Span Assessment is still valid or to determine a new plan that is more appropriate for the unit. The reassessment of unit life span can be undertaken for any of the following **Reassessment Criteria**:

- Annual Business Plan Review
- Last Decade of Unit Life Span
- Environmental Compliance
- Infrastructure
- Significant Event
- Commission Ordered Reassessment.

When a reassessment is undertaken, it can range from cursory to detailed, dependent on the nature of the revisit. For example, during the initial years of operation, the reassessment due to an Annual Business Plan Review may result in a business decision to maintain the Initial Life Span Assessment. The other end of the spectrum would be a unit entering its planned last decade of operations where operations, maintenance, environmental and infrastructure issues could dictate a detailed review to assess the remaining life span. No matter the nature of the review, the key steps of the **Reassessment Protocol** are as follows:

- Unit Assessment
- Environmental Assessment
- Infrastructure Assessment
- Development of Options
- Options Input to Resource Planning and Financial Analysis
- Final Decision on Life Span Assessment and Implementation Plan

Per the approved LSAP, the following reassessment criteria have been met, triggering an evaluation of the operating life for the Units.

- Unit is within 10 years of last approved retirement date

The following provides a brief explanation of the above trigger and determines the criticality of each trigger for the LSAP analysis.

[1] The Life Span Analysis Process was approved by the Commission in Docket No. 08-08002

<u>Unit Is Within 10 Years of Last Approved Retirement Date</u>

The latest Integrated Resource Plan filing for Nevada Power shows a retirement date of December 31, 2026 for the Units. This was based on due diligence performed prior to the purchase of the Units and was based on a review of the relevant data available to the due diligence team. Since replacement capacity would take a number of years to permit, design and construct, and investments in replacement units would be required within the next Action Plan period to ensure replacement capacity is available if the Units are planned to retire in 2026, it is prudent to review this retirement date at this time.

3.1 Unit Condition Considerations

The Units began operating on June 8, 1991 with Oxbow Power Corporation as the managing partner. At the same time, Nevada Power accepted the Units 5 from Oxbow Power Corporation for commercial operation. In turn, the Units were released to the Nevada Power's system dispatcher for operational duty.

The Units are GE Frame 7EA, simple cycle. Emissions limits are 42 PPM NOX / 10 PPM CO on a three-hour average basis when fired on natural gas.

Throughout the years the site was sold to several different owners, but continued to be available for Nevada Power's operational dispatch. Some of the major maintenance that was performed was:

- 1999 - Unit-5 Hot Gas path to fix 1st. stage bucket migration.
- 2002 - Unit-4 Major Turbine overhaul and Generator re-wedge.
- 2003 - Unit-3 Major Turbine overhaul and Generator re-wedge.
- 2005 - Unit-5 Major Turbine overhaul and Generator re-wedge.
- 2008 - Partial discharge system installed on all units.
- 2014 - NV Energy took over ownership of Sun Peak.
- 2014 - Unit-4 Main Gas valve replace due to excessive leaking.
- 2015 - Continuous Emissions monitoring system complete upgrade.
- 2015 - Replaced both instrument air compressors with Atlas Copco Model ZT22 units.
- 2015 - All evaporative inlet media was replaced on all units.
- 2016 - DCS system was upgraded.
- 2017 - Unit-5 Hot Gas Path to fix 1st. stage bucket migration.
- 2018 - Unit-3 Main Gas valve replace due to excessive leaking.
- 2018 Units 3-5 Install Online Generator Step-Up Transformer Dissolved Gas Monitoring
- 2018 – Units 3-5 Inlet Air Filter Replacement
- 2018 – Install Automatic Fuel Shut Off Valve
- 2018 – Unit 4 Buss Duct Replacement
- 2018 – Replace Ultra Violet Disinfection System
- 2018 – Units 3-5 Replace Turbine Compartment Gas Leak Detection System

A new Emerson Excitation system was purchased to be installed 2019.

At the present time:

Unit-3 is at 2,680 total starts with 10,810 fired hours.

Unit-4 is at 2,617 total starts with 10,751 fired hours.

Unit-5 is at 2,649 total starts with 10,267 fired hours.

3.2 Environmental Considerations

The Units are currently in compliance with all environmental agency issued permits and associated limits. No other specific environmental regulations are known at this time that would directly impact the operations of the Units.

On April 30, 2018, Environmental Protection Agency released a prepublication designating the Las Vegas Valley as nonattainment with the 2015 National Ambient Air Quality Standard for ozone. This designation will trigger the Clark County Department of Air Quality to take steps to reduce ozone pollution to bring the area into attainment with the standard. No effect on the Units is currently anticipated as the agency's actions are expected to have the most impact on new construction, not existing facilities.

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3.3 Infrastructure Considerations

Infrastructure for a unit includes all those support systems that allow a unit to generate and deliver power to the customer. They include land, roads, railways, fuel supply, water supply, transmission access and other features.

The LSAP focuses on current and forecasted changes to the infrastructure elements. There are contracts on many of these infrastructure components and at any time during the life span of the unit, the renewal, expiration or negotiation of these contracts may result in impacts to the economic viability of the unit. Similarly, market conditions are associated with some Infrastructure components, with fuel being a prime example.

There are currently no infrastructure concerns for the Units.

4.0 OPTION DEVELOPMENT

The alternatives identified for the future utilization of the Units represent different options of capital investments in the facilities to allow safe and reliable operation of the unit in accordance with environmental regulations.

Since these are peaking units and Nevada Power is operating at a capacity deficit, no early retirement option was identified. Continuing operations for an additional five years was chosen as a consistent life compared to the lives recommended for the other GE 7EA units in Nevada Power's and Sierra's systems.

4.1 Base Case, Retire all three Sun Peak Units on December 31, 2026

This base case assumes that all three of the Units operate until the eve of December 31, 2026 as planned. This alternative does not include any significant investment in capital for the remaining life of the Units, other than normal turbine maintenance based on operating hours and unit starts. The Units can be expected to continue operating on an as needed basis to support the transmission grid as necessary in addition to providing energy until their retirement. At retirement on December 31, 2026, Nevada Power would retire the plant.

4.2 Option A – Extend operation to 2031

This alternative assumes that all three of the Units operate an additional five years, until the eve of December 31, 2031. This alternative does not include any significant investment in capital for the remaining life of the Units, other than normal turbine maintenance based on operating hours and unit starts. The Units can be expected to continue operating on an as needed basis to support the transmission grid as necessary in addition to providing energy until their retirement. At retirement on December 31, 2031, Nevada Power would retire the plant and begin decommissioning and demolition of the Units.

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5.0 PLANNING ASSUMPTIONS

The following planning assumptions are used in the ProMod analysis and are used in Nevada Power's business planning.

5.1 Labor

The Sun Peak site is currently staffed with five full time employees. Four of the employees are operators. During seasonal operation, the four operators work a rotating shift to provide coverage. During months of reserve shutdown the plant operators work a day shift and support plant maintenance. The fifth employee provides maintenance support year round for the site.

5.2 Expected Operations Strategy:

The Units are anticipated to remain summer only operated assets. The Units will typically be made available for dispatch between May to October annually. During the winter months the Units will be in reserve shutdown status.

6.0 OPTION ANALYSIS

6.1 Economic Analysis

As described in the sections above, the Units are expected to have a rather low capacity factor (approximately 1.1 percent) for the remainder of their operating life. Since it is difficult to predict when the Units will operate, the energy value of the units is not included in this analysis. Instead, the analysis will evaluate the capacity value of the Units.

Currently, Nevada Power relies on the market to provide a portion of its capacity needs. When the Units retire, their capacity must be replaced – either by another unit or by acquiring even more capacity from the market. This analysis will compare the fixed cost of continuing the operation of the Units to the end of 2031 with the cost of purchasing an equivalent amount of capacity from the market for the same time period.

Figure 4 – Economic Analysis Results

	Market Capacity Price ($/kW-yr)	SunPeak 3-5 Dependable Capacity (kW)	Cost to replace SunPeak 3-5 Capacity ($/yr)	Fixed Operating Cost of SunPeak 3-5 ($/yr)	Saving from continued operation of SunPeak 3-5
2027	$77.78	132,000	$ 10,267,426	$ 362,433	$ 9,904,992
2028	$81.58	132,000	$ 10,768,899	$ 369,682	$ 10,399,217
2029	$85.95	132,000	$ 11,345,670	$ 377,076	$ 10,968,595
2030	$90.00	132,000	$ 11,879,990	$ 384,617	$ 11,495,372
2031	$91.01	132,000	$ 12,013,836	$ 392,309	$ 11,621,526

The table shows continued operation of the Units saves between $9.9 and $11.6 million per year. The Units enjoy significant capacity value even though they have little energy value.

7.0 LSAP RETIREMENT DATE RECOMMENDATION

The recommendation of this LSAP is to plan for the continued operation of the Units for an additional five years. No extraordinary capital investments are required for the continued operation of the nits through 2031. The present worth revenue requirement analysis shows that continued operation of the Units is the most economic management of the asset. Continued operation of the Units provides a ready capacity and energy

resource for Nevada Power's system and reduces the capacity deficit at peak, compared to retiring the Units on schedule. Though there are no other known approved or pending environmental regulations that would materially affect the Units, the Company currently believes there would be a high level of uncertainty forecasting environmental capital requirements to operate these Units beyond 2031. In addition, the peaking operation of these Units and their quick start capability will continue support the addition of more intermittent renewable resources supplying Nevada Power's system. Nevada Power recommends modifying the planning retirement date for all three of the Units to reflect another five years of available operation and setting the planning retirement date as 2031.