PNM
2017-2036

Integrated Resource Plan

Balancing cost and reliability while reducing the impact on the environment

July 3, 2017

A NEW CENTURY OF SERVICE

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APPENDICES

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APPENDIX A. LOAD FORECAST DETAILS AND DISCUSSION

Table 1. 2017 IRP Mid–Low–High Demand Forecasts (one of three)

Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MID																				
Load Total	1,911	1,961	2,009	2,056	2,108	2,163	2,201	2,230	2,260	2,291	2,323	2,356	2,390	2,424	2,460	2,496	2,534	2,572	2,610	2,650
Energy Efficiency (incremental)	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)	(136)	(138)	(146)	(147)	(142)	(138)	(135)	(134)	(129)	(122)
PV-DG (incremental)	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(47)	(48)
Net System Total	**1,871**	**1,900**	**1,926**	**1,961**	**1,999**	**2,041**	**2,064**	**2,082**	**2,105**	**2,125**	**2,150**	**2,180**	**2,204**	**2,236**	**2,276**	**2,315**	**2,354**	**2,392**	**2,435**	**2,480**
LOW																				
Load Total	1,906	1,896	1,904	1,929	1,953	1,963	1,976	1,991	2,008	2,027	2,046	2,067	2,089	2,112	2,135	2,159	2,184	2,209	2,235	2,261
Energy Efficiency (incremental)	(23)	(36)	(51)	(63)	(77)	(91)	(105)	(116)	(124)	(135)	(143)	(147)	(157)	(161)	(157)	(154)	(153)	(154)	(151)	(145)
PV-DG (incremental)	(18)	(31)	(42)	(44)	(44)	(45)	(46)	(47)	(48)	(49)	(51)	(52)	(53)	(54)	(55)	(57)	(58)	(59)	(60)	(62)
Net System Total	**1,865**	**1,830**	**1,810**	**1,822**	**1,832**	**1,827**	**1,825**	**1,828**	**1,835**	**1,842**	**1,852**	**1,869**	**1,879**	**1,897**	**1,923**	**1,948**	**1,973**	**1,996**	**2,024**	**2,055**
HIGH																				
Load Total	1,915	2,003	2,078	2,175	2,269	2,361	2,439	2,509	2,561	2,602	2,645	2,688	2,732	2,778	2,824	2,872	2,921	2,971	3,023	3,076
Energy Efficiency (incremental)	(23)	(35)	(50)	(61)	(73)	(85)	(97)	(105)	(111)	(118)	(123)	(123)	(129)	(128)	(122)	(118)	(114)	(112)	(107)	(100)
PV-DG (incremental)	(18)	(19)	(21)	(19)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(26)	(27)	(28)	(29)	(31)	(32)	(33)	(34)
Net System Total	**1,875**	**1,948**	**2,007**	**2,095**	**2,176**	**2,257**	**2,321**	**2,382**	**2,427**	**2,461**	**2,497**	**2,540**	**2,577**	**2,622**	**2,673**	**2,725**	**2,776**	**2,828**	**2,884**	**2,943**

Table 2. 2017 IRP Mid, Low, and High Energy Forecasts (two of three)

Energy (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MID																				
Load Total	9,040	9,195	9,544	9,862	10,170	10,475	10,650	10,729	10,802	10,902	10,956	11,037	11,111	11,190	11,269	11,351	11,428	11,507	11,588	11,671
Energy Efficiency (incremental)	(197)	(284)	(401)	(511)	(610)	(695)	(756)	(815)	(872)	(928)	(969)	(988)	(1,001)	(1,006)	(1,000)	(984)	(959)	(932)	(906)	(881)
PV-DG (incremental)	(47)	(83)	(118)	(150)	(151)	(153)	(156)	(159)	(161)	(164)	(167)	(170)	(173)	(176)	(179)	(182)	(185)	(188)	(191)	(194)
Net System Total	**8,796**	**8,828**	**9,025**	**9,201**	**9,410**	**9,627**	**9,737**	**9,755**	**9,769**	**9,809**	**9,820**	**9,879**	**9,938**	**10,009**	**10,091**	**10,186**	**10,284**	**10,388**	**10,490**	**10,597**
LOW																				
Load Total	8,998	8,980	9,105	9,328	9,465	9,460	9,461	9,454	9,445	9,436	9,428	9,421	9,411	9,402	9,394	9,387	9,376	9,368	9,359	9,352
Energy Efficiency (incremental)	(197)	(284)	(402)	(514)	(617)	(706)	(773)	(839)	(905)	(971)	(1,022)	(1,053)	(1,079)	(1,096)	(1,103)	(1,100)	(1,087)	(1,072)	(1,057)	(1,042)
PV-DG (incremental)	(47)	(102)	(156)	(207)	(208)	(210)	(213)	(216)	(219)	(221)	(224)	(227)	(230)	(233)	(236)	(239)	(242)	(245)	(248)	(251)
Net System Total	**8,754**	**8,594**	**8,547**	**8,607**	**8,640**	**8,544**	**8,474**	**8,399**	**8,322**	**8,244**	**8,182**	**8,141**	**8,102**	**8,073**	**8,055**	**8,048**	**8,047**	**8,051**	**8,054**	**8,059**
HIGH																				
Load Total	9,088	9,284	9,670	10,130	10,749	11,339	11,792	12,149	12,368	12,522	12,625	12,783	12,892	13,033	13,171	13,318	13,461	13,614	13,764	13,924
Energy Efficiency (incremental)	(195)	(278)	(389)	(493)	(584)	(660)	(711)	(760)	(805)	(850)	(878)	(885)	(888)	(882)	(867)	(846)	(817)	(786)	(756)	(726)
PV-DG (incremental)	(47)	(64)	(79)	(93)	(93)	(96)	(99)	(101)	(104)	(107)	(110)	(112)	(115)	(118)	(121)	(124)	(127)	(130)	(134)	(137)
Net System Total	**8,847**	**8,942**	**9,201**	**9,544**	**10,071**	**10,583**	**10,982**	**11,288**	**11,459**	**11,564**	**11,637**	**11,786**	**11,889**	**12,033**	**12,182**	**12,348**	**12,517**	**12,698**	**12,975**	**13,061**

Table 3. 2017 IRP Demand Forecast with Transmission and Distribution Losses at Peak Demand Hour (three of three)

Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MID Forecast -- Load and Losses at Peak Demand Hour																				
Load at Delivery	1,731	1,779	1,825	1,869	1,919	1,972	2,007	2,033	2,060	2,088	2,117	2,147	2,178	2,209	2,241	2,274	2,309	2,343	2,377	2,414
Transmission Losses	78	78	79	80	81	82	84	85	86	87	89	90	91	93	94	96	97	99	100	102
Distribution Losses	102	104	105	106	108	109	110	112	114	115	117	119	121	122	124	126	128	130	132	135
Load Total	**1,911**	**1,961**	**2,009**	**2,056**	**2,108**	**2,163**	**2,201**	**2,230**	**2,260**	**2,291**	**2,323**	**2,356**	**2,390**	**2,424**	**2,460**	**2,496**	**2,534**	**2,572**	**2,610**	**2,650**
Energy Efficiency (incremental)	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)	(136)	(138)	(146)	(147)	(142)	(138)	(135)	(134)	(129)	(122)
PV-DG (incremental)	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(47)	(48)
Net System Total	**1,871**	**1,900**	**1,926**	**1,961**	**1,999**	**2,041**	**2,064**	**2,082**	**2,105**	**2,125**	**2,150**	**2,180**	**2,204**	**2,236**	**2,276**	**2,315**	**2,354**	**2,392**	**2,435**	**2,480**

Table 4. 2016 Sales Statistics

Customer Class	Customers	Electric Sales (MWh)	Revenue ($000)
Residential	462,921	3,189,527	$395,490
Commercial	56,357	3,831,295	$394,150
Industrial	247	875,109	$56,650
Public Authority	n/a	249,860	$23,174
Economy Service	1	805,733	$31,121
Transmission	n/a	0	$34,267
Firm Wholesale	36	429,345	$22,497
Other	887	2,899,322	$78,564
Total	**520,449**	**12,280,191**	**$1,035,913**

Table 5. 2017 Projected Coincident Peak Demand

Rate Classification	kW at Peak Hour
1 - Residential	893,770
2 - Small Power	261,165
3B - General Power	305,597
3C - General Power Low LF	48,434
4B - Large Power	215,495
5B - Lg. Svc. (8 MW)	19,999
10 - Irrigation	6,925
11B - Wtr/Swg Pumping	17,409
15B - Universities 115 kV	19,415
30B - Manuf. (30 MW)	55,098
33B - Lg. Svc. (Station Power)	0
35B - Lg. Svc. (3 MW)	27,303
36B - SSR - Renew. Energy Res.	0
6 - Private Lighting	0
20 - Streetlighting	0
Total	**1,870,609**

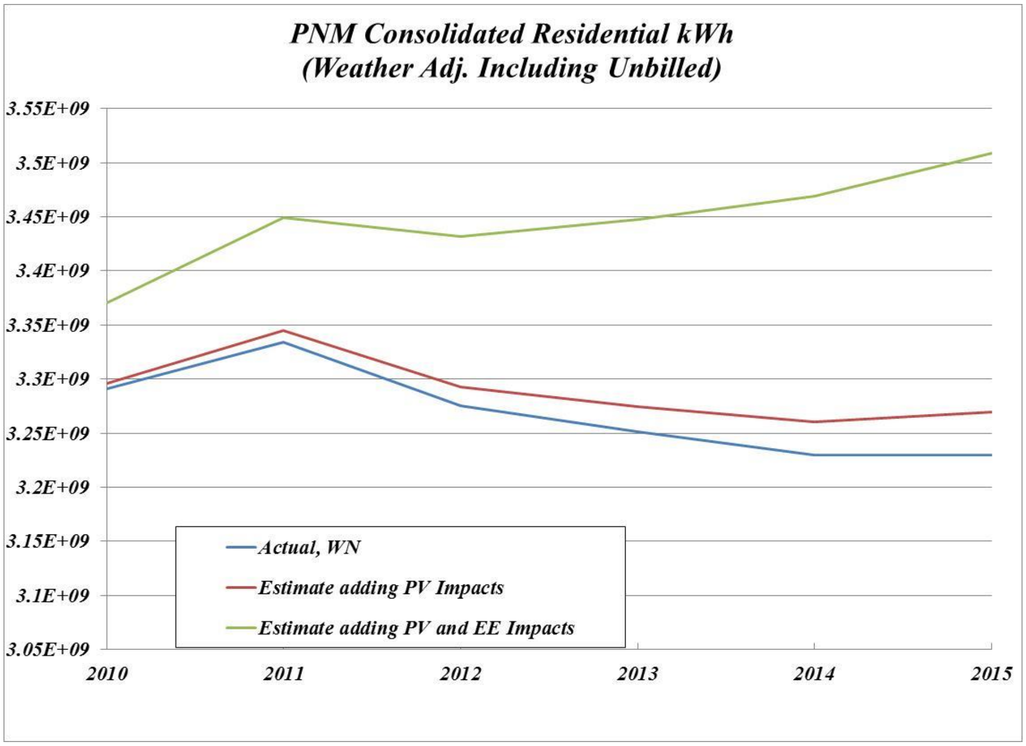
Residential Forecast Methodology

PNM based the residential energy sales forecast on forecasts of customer growth and forecasts of per-customer usage. This methodology for determining residential growth has been adopted as the implementation of energy efficiency programs and roof-top solar installations has dramatically impacted the growth in this sector. Specifically, the energy sales forecast combines the separate customer count and use per customer forecasts. Residential energy sales then equals the customers forecast multiplied by the usage per customer forecast.

Customer growth over time is based on population growth forecasts. Historical population growth has been correlated with historical customer growth. Using population growth projections tailored to PNM's service territory from the Bureau of Business and Economic Research at the University of New Mexico, PNM applies the historical relationship between population and customer growth to produce forecasted customer growth.

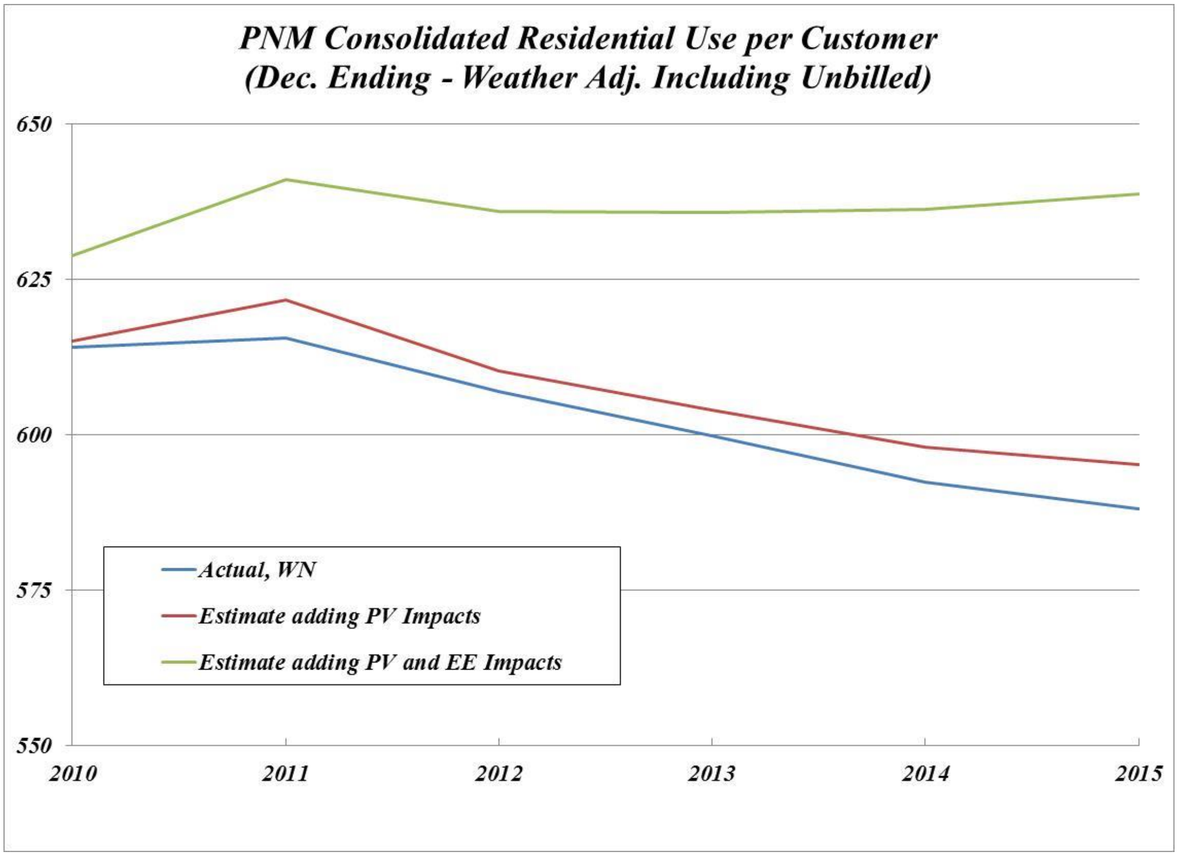
To calculate usage per customer, PNM first forecasts use per customer based on (1) the seasonal usage differences within a year, (2) responses to weather, and (3) changes in usage patterns over time that result from lifestyle changes, price, and historical appliance efficiency improvements, but separating impacts of PNM's future energy efficiency programs and customer owned distributed generation (Private DG). This underlying forecast assumes normal weather derived from a 10-year average (2006 to 2015) of heating and cooling degree days. Once this forecast is completed, then impacts of PNM's energy efficiency programs and Privater DG programs are used to create a final use per customer forecast. Figure 1 provides a historical look at the impact of PNM's energy efficiency programs and Private DG.

Figure 1. Total PNM Residential Sales



Each year PNM develops a 20 year energy efficiency program plan. Under the existing rules, PNM spends 3% of total retail revenue on energy efficiency programs. PNM implements the most cost effective programs first and as a result, over time, while the total spent on energy efficiency is growing as the rate of retail revenue growth, program savings declines. A similar phenomenon is projected to occur with Private DG. The number of new Private DG is higher in the near term and as the market becomes saturated, there are fewer new customers forecasted. Figure 2 shows the use per customer forecast before the energy efficiency and Private DG are included in the forecast.

Figure 2. Residential Use Per Customer



Commercial Forecast Methodology

The FERC defined commercial customer class contains 10 PNM rate classes. The energy sales forecasts of the small power and general power classes were prepared in the same way as the two residential rate classes, by multiplying forecasts of the number of customers by forecast per customer use. As with the residential forecast, historical trends and employment estimates from the Bureau of Business and Economic Research at the University of New Mexico were used as inputs in the commercial customer forecast equation to help capture economic conditions.

PNM prepared forecasts of the larger customers within the commercial class differently. Forecasts for the largest commercial customers, managed by internal account managers, were prepared on an individual basis. PNM's internal account managers routinely contacted these customers and provided updates on their expected energy use. The account managers also helped to identify if any potential new large customers anticipated starting service in the forecast period.

Industrial Forecast Methodology

Like the commercial FERC class, the industrial class may receive service under several PNM rate classes. PNM serves just under 250 industrial customers, the largest 40 making up the majority of total industrial segment energy sales. The largest industrial customers receive service under four rates (rate schedules 4B, 5B, 30B, and 33B). PNM energy sales forecasts for these customers reflect information obtained directly from the account managers, who are in contact with these customers in the same manner as for large commercial customers. PNM, through its quarterly update process, continually evaluates forecasts for these large customers.

PNM prepared forecasts for the remaining industrial customers, those served under either small power or general power rate schedules, in the same way it prepared the forecasts for their counterparts in the commercial class—by aggregating all customers within a rate class and performing statistical time-series analyses. PNM prepared autoregressive statistical models based upon the historical relationship between time, weather, and non-weather monthly variations and usage. For the large power customers that did not receive individual forecasts, PNM forecasts aggregate use for that group rather than use per customer multiplied by a customer count forecast. Change in industrial use per customer is not as easily predictable from historical data as the other classes. Industrial customer usage is directly dependent on the size and nature of industrial customers entering or exiting PNM territory, more so than the economic trends used to predict residential sector growth. Industrial load is affected by weather, but not to the extent that weather-driven space heating and cooling affect the residential and commercial classes' load.

Separate load forecasts for firm wholesale customers were prepared using recent history and known contract changes for the future.

Transmission and 46 kV and 69 kV Demand and Energy Loss Calculation Methodology

Transmission Demand and Energy Loss Calculation Methodology

Actual transmission losses from a 2015 loss study were used to develop the transmission losses used in the forecast. The historical loss factor is applied to the energy forecast after the demand losses for each hour of the energy forecast to determine the total energy needed at the generator to meet the total sales energy forecast. The historical peak demand loss factor is used to increase the forecasted peak forecast including distribution losses.

The historical energy losses are determined from hourly metered data that measure the total amount of energy entering and leaving the PNM operated transmission system in the PNM BA where losses are essentially equal to the sum of all meters. This represents the amount of power that flowed into the transmission system but did not flow back out to load. The meters include the transmission line meters and the distribution substation meters and the source of the metered data includes Supervisory Control and Data Acquisition (SCADA) data, DOC operations data and energy accounting data. In addition energy losses we pay to third parties on jointly owned facilities and for wheeling on third party systems are added to the metered losses. Third party losses are based on OATT loss rates for wheeling on third party systems and agreed upon percentages for jointly owned facilities. The agreed upon percentages are typically developed from historical studies that use metered data for the power flowing into and out of the jointly owned facilities.

The historical transmission demand losses are determined from powerflow cases that model the operating conditions for the peak hour of each month. The operating conditions are taken from SCADA, energy accounting and DOC operations data. The powerflow program calculates losses for each transmission line on PNM's system based on the line modeling parameters and the calculated flow for the peak hour operating conditions. The sum of the losses on all PNM operated transmission lines in the PNM BA area represents the demand losses for the peak hour of the given month. The process results in 12 monthly historical demand loss values. Demand is not adjusted for third party wheeling or jointly owned facilities.

Distribution (4.16 kV through 13.8 kV) Demand and Energy Loss Calculation Methodology

Actual distribution losses for the period 2012 – 2014 were used to develop the distribution losses used in the forecast. The energy losses are determined as a percentage of retail sales. That loss percentage is then used to increase all hours of the load forecast in order to assess the amount of energy needed to serve the total load after distribution losses have been accounted for. The peak demand loss factor is used to increase the forecasted peak demand.

The methodology used to calculate the distribution system losses compared the general ledger customer kilowatt-hours to the substation hourly kilowatt loading data from Jan 2012 – Dec 2014. The substation hourly kilowatt loading data values were also used in conjunction with substation transformer manufacture parameters to determine losses through individual substation transformers.

To calculate distribution system losses for energy, the Jan 2012 – Dec 2014 billed energy was subtracted from the Jan 2012 – Dec 2014 calculated load data measured on the distribution voltage side of each substation transformer, typically at 12.47kV. The substation transformer kWh is calculated by summing the measured kW for each substation transformer for each hour of the thirty-six-month period. A single kW value is captured for each hour and is the assumed average kWh value for the hour.

To calculate substation transformer losses, two components were determined; core losses and winding losses. Each type of loss was computed using individual transformer data for each of the system transformers, then summed over all of the transformers to obtain the total losses. Core losses were computed by multiplying the no-load loss value provided on each individual transformer's manufacturer test report times the number of hours that transformer was in-service during the study period. Winding losses were computed by multiplying the load loss value provided on each individual transformer's manufacturer test report times the square of the load on that transformer during the study period.

PNM Energy Efficiency Programs, Rooftop Solar, and Codes and Standards Decrement Forecasts Methodologies

Incorporated into the load forecast are reductions in energy consumption caused by PNM's energy efficiency programs under the EUEA requirements, estimates for rooftop solar adoption by PNM's customers (private solar), and projections for increased energy efficiency based on future codes and standards. PNM developed an energy and demand savings forecast of PNM's energy efficiency and load management programs (EE Forecast) over the 20-year IRP planning period. Energy and demand savings are a function of the level of spending on the programs and the savings achieved per dollar spent. The level of spending is proscribed by the EUEA and is equivalent to 3% of PNM's retail revenues. Historically, the savings achieved per dollar spent have been decreasing. In other words, it is becoming more expensive to achieve a given level of savings because of a number of factors, including saturation of low-cost measures. The EE Forecast was developed by estimating the annual spending level and estimating a rate of increase in the cost of delivering savings over time based on historical trends. The EE Forecast was developed by dividing historical results kWh of savings per dollar into the required EUEA spending of the future. Energy efficiency gains are inherent in the historical data. In order to avoid double counting the historical benefits of energy efficiency, PNM assumes that all historical gain through 2016 are included in the forecast, and has treated only incremental gains after 2016 in energy efficiency programs as a separate component.

PNM developed the rooftop solar energy decrement forecast by multiplying the historical capacity of the system across photovoltaic (PV) customers with the total effective sun hours of a fixed-tilt south-facing solar panel in Albuquerque during each month (solar resource information was provided by the National Renewable Energy Laboratory). PNM determined the historical capacity of the of all rooftop systems in its service territory prior to 2016 by the total kW AC of all the interconnected customers for the same time period, providing an average output for each kW AC installed. Additionally, PNM took the total kW AC and divided it by the total number of interconnected customers to determine the average installation size. For the period 2016 through 2021, PNM assumed the same number of interconnections as in 2015 and then multiplied that by the average system size and average output per system to determine the PV decrement for those years. After 2021, PNM has assumed a slowing down of the number of new interconnected customers due to market saturation and used a growth factor of 1.4%.

PNM prepared the codes and standards decrement forecast using LoadMAP, an end-use model developed and maintained by the Applied Energy Group.[1] LoadMAP addresses a variety of forecast drivers, including appliance standards, by computing electricity consumption for each major appliance category for residential and commercial customers. As an end-use or bottom-up model, LoadMAP gathers information on how many appliances of each efficiency level are in the existing stock of homes and how many appliances of each efficiency level are in the new market, consisting of replacements and new construction. It then computes the energy used by all the existing and new appliances, assuming that the appliances run for a specified number of hours per year under designated weather conditions.

The Energy Independence and Security Act (EISA) advances energy efficiency initiatives including lighting and appliance mandates. The EISA also requires the U.S. Department of Energy (DOE) to determine if more stringent, amended standards for these products are technologically feasible and economically justified. For example, an update to the residential refrigerators standard occurred in 2014. As customers replace their refrigerators, this standard will result in a reduction in use per customer. New lighting standard effecting general lamps will go into effect in 2020. As with the other lighting standards, PNM has assumed that the impact of the change will actually begin in 2019. PNM has addressed this as a separate component in the forecast.

[1] Information about the Applied Energy Group's LoadMAP tool is available at the Applied Energy Group website at http://www.appliedenergygroup.com/load-and-revenue-forecasting.

Historical Comparison of Load Forecasts

Table 6 and Table 7 show historical load forecasts compared to actual load. The columns represent forecast cycle and the rows represent the year forecasted. For example, row 2015, column 2016, represents 2016's demand as forecasted in 2015. Each year of historical forecast in this table was prepared in the year shown at the top of each column.

Table 6. PNM System Peak Demand Comparison

Forecasted Peak Demand (MW)	2013	2014	2015	2016	Actual	Weather Normalized Actual
2013	1,978				2,008	1,977
2014	1,984	1,983			1,969	1,963
2015	2,000	1,991	1,945		1,889	1,857
2016	2,012	1,997	1,970	1,947	1,908	1,911

Table 7. PNM System Energy Comparison

Forecasted Energy Sales (GWh)	2013	2014	2015	2016	Actual	Weather Normalized Actual
2013	10,129				10,130	10,069
2014	10,191	9,832			9,702	9,782
2015	10,245	9,853	9,427		9,580	9,642
2016	10,317	9,863	9,377	9,317	9,403	9,464

PNM's past demand forecasts tended to over-forecast system peak demands on a weather-normalized basis. A key factor contributing to this has been declining sales growth in the aftermath of the recent economic recession. The overriding factor has been the poor performance of the New Mexico economy relative to the national and regional recoveries since the recession. In addition to the slow recovery PNM has seen a significant drop in load factor over the past 10 years as described below. Figure 3 and

Figure 4 show each year's forecast in comparison to other years, along with the actual loads for that year. These graphs clearly show that forecasts have both been over and under the actual system performance leading to the need to evaluate the IRP around a range of load forecasts and not one point forecast.

Figure 3. PNM's Historical Energy Forecasts

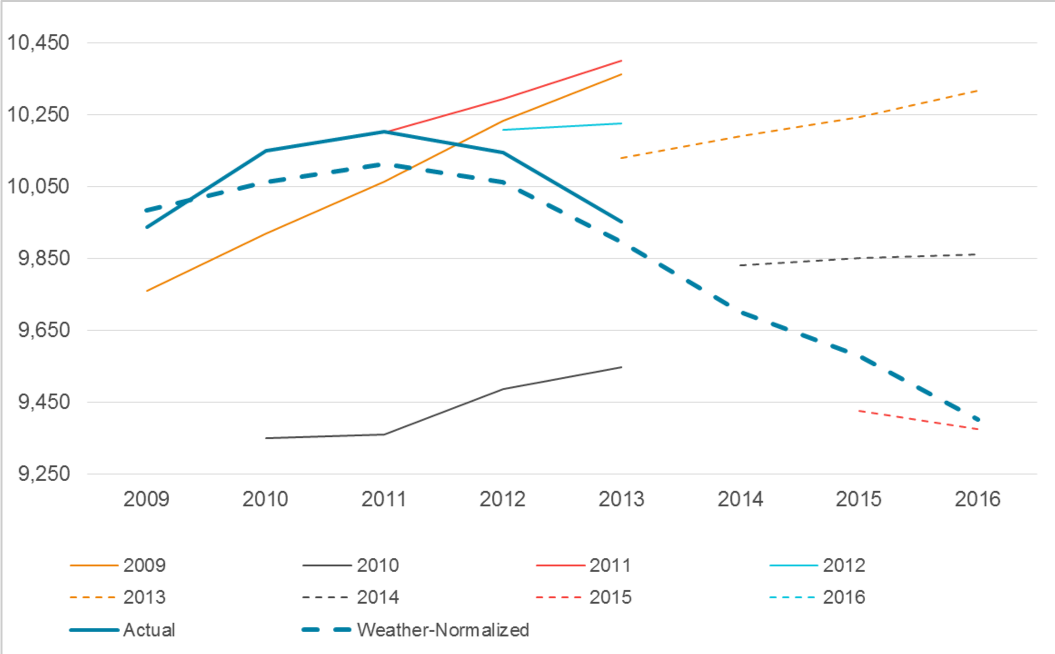
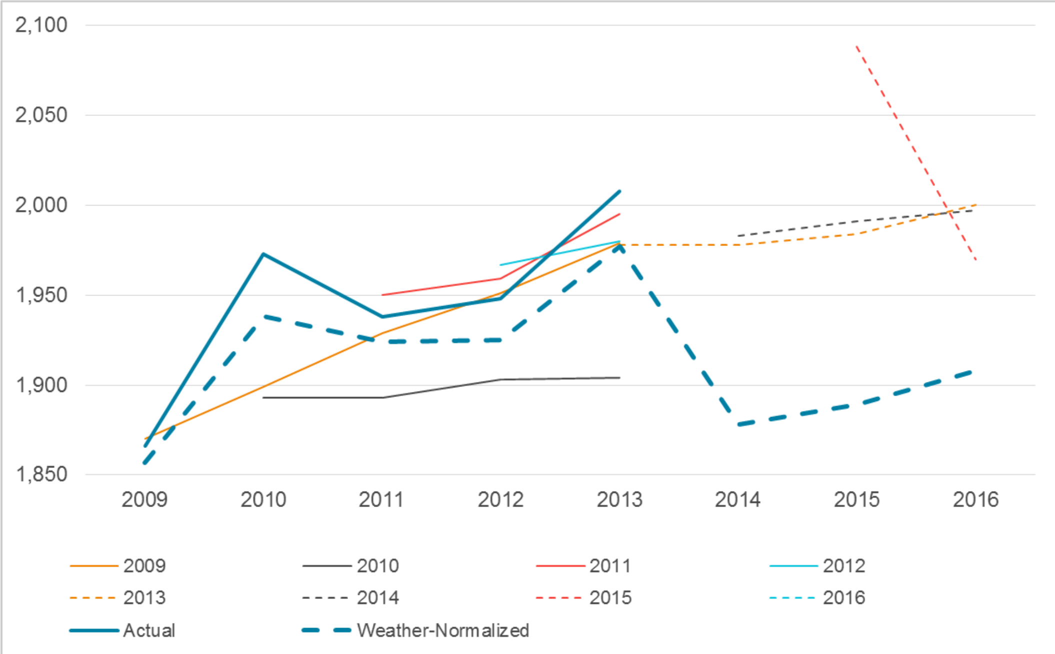


Figure 4. PNM's Historical Demand Forecasts



Load Factor

Load factor is a measure of average customer demand divided by peak customer demand. It represents an expectation of the amount of time that resources necessary to meet peak customer load is likely to be required for non-peak load, thereby affecting the selection of the type of generation resource that PNM may develop as peak demand grows over time.

As shown in Table 8, PNM has seen a deteriorating load factor for both the total system and the retail portion of PNM's load. PNM attributes this trend to two factors: (1) residential customers replacing evaporative space cooling with refrigerated air conditioning, thereby increasing summer peak demand, and (2) PNM's energy efficiency programs, which are reducing energy use.

Table 8. PNM System Load Factor Summary

Year	Actual
2006	63.60%
2007	62.70%
2008	63.00%
2009	60.80%
2010	58.70%
2011	60.10%
2012	59.30%
2013	56.60%
2014	58.97%
2015	57.90%
2016	56.26%

The system load factor has fallen below 60% in several recent years, which represents a significant decrease from averages of around 63% seen in the early 2000s. Whether this deterioration will continue is difficult to predict for the forecast period. Although recent history would infer continuing deterioration, PNM's demand response programs "shave" peak demand, whereas rate structure encourages load shifting from on-peak hours to off-peak hours.

The current forecast assumes a moderately decreasing system load factor absent development of further initiatives to improve it.

Private Distributed Generation (DG)

Customers on PNM's system, or third parties contracting with the customer, are eligible to construct solar photovoltaic (PV) systems behind PNM's electric meter at their place of residence or business. They also receive energy bill savings when the customer's generation exceeds their consumption. By participating in PNM's solar DG program, customers may also sell the Renewable Energy Certificates (RECs) generated by their solar system to PNM, which uses the RECs for New Mexico Renewable Portfolio Standard (RPS) compliance. The interconnection of these facilities to PNM's system, the administration of the private credits program, and the purchase of the RECs by PNM from solar facilities sized up to 1 MW are subject to the requirements of applicable PNM tariffs that have been reviewed and approved by the NMPRC.

Private solar PV installations are a small but fast-growing resource on PNM's system. Customers who choose to install a qualified solar PV or solar thermal electric system at their homes or businesses (or that are installed and owned by third parties) are eligible for PNM programs that allow customers to receive private credits and to sell the RECs associated with the energy to PNM. Although these customer-sited systems decrease net system demands, PNM provides backup service to interconnected customers, which ensures the customer still has electricity service if their solar system is temporarily out of service for any reason.

Customer installations continue to grow both in number and in the size of systems. This is attributable to federal and state tax incentives, the current downward trend in the cost of PV systems, private credits, and REC payment incentives offered by PNM. Table 9 shows the number of customers participating in the private solar programs, the installed capacity, annual RECs, and the peak-hour generation for each year since 2006.

Table 9. Private Renewable Distributed Generation

Year	Cumulative Number of Participants	Cumulative KWAC Installed	Annual RECs (MWh)	Peak Hour Generation KWAC (55% of capacity)	Percentage of Growth over Previous Year
2006	93	164	413	90	
2007	187	348	1,593	191	112%
2008	368	748	3,525	411	115%
2009	708	2,124	7,132	1,168	184%
2010	1,342	6,165	13,611	3,391	190%
2011	2,192	14,208	26,767	7,814	130%
2012	2,994	19,894	41,914	10,942	40%
2013	3,777	31,441	56,366	17,293	58%
2014	5,071	39,372	85,239	21,655	25%
2015	5,422	42,550	93,577	23,403	8%
2016	8,710	62,830	119,574	34,557	48%

Although these installations are the responsibility of the system owners, PNM assumes that these installations will be maintained because customers receive net-metering and REC payments. For IRP purposes, it was assumed that existing distributed generation installations will continue to operate to offset system load for the entire planning period.

The PNM rates and tariffs that govern customer-sited renewable development include the following:

- **Photovoltaic Renewable Energy Certificate Procurement Rates (Rate 24, Rate 31, and Rate 32):** These rates incentivize customers to install solar facilities on their premises and sell the RECs to PNM for RPS compliance. Rates 24 and 31 are closed to new participants because those programs were superseded by Rate 32.
- **Cogeneration and Small Power Production Rate (Rate 12):** This rate, based on PNM's energy costs in the corresponding month of the prior year, is offered to qualifying facilities that provide net-excess renewable generation to PNM.

Typical Week Load Profiles

Figure 5 through Figure 8 show a typical week load profile on PNM's system in January, April, July, and October to illustrate the variability of load on the system caused by the season of the year as well as the differences in load variability during the day and week during those months. Dotted lines illustrate the impact of wind and solar resources on PNM's load patterns.

Figure 5. January Load Profile: Typical Week

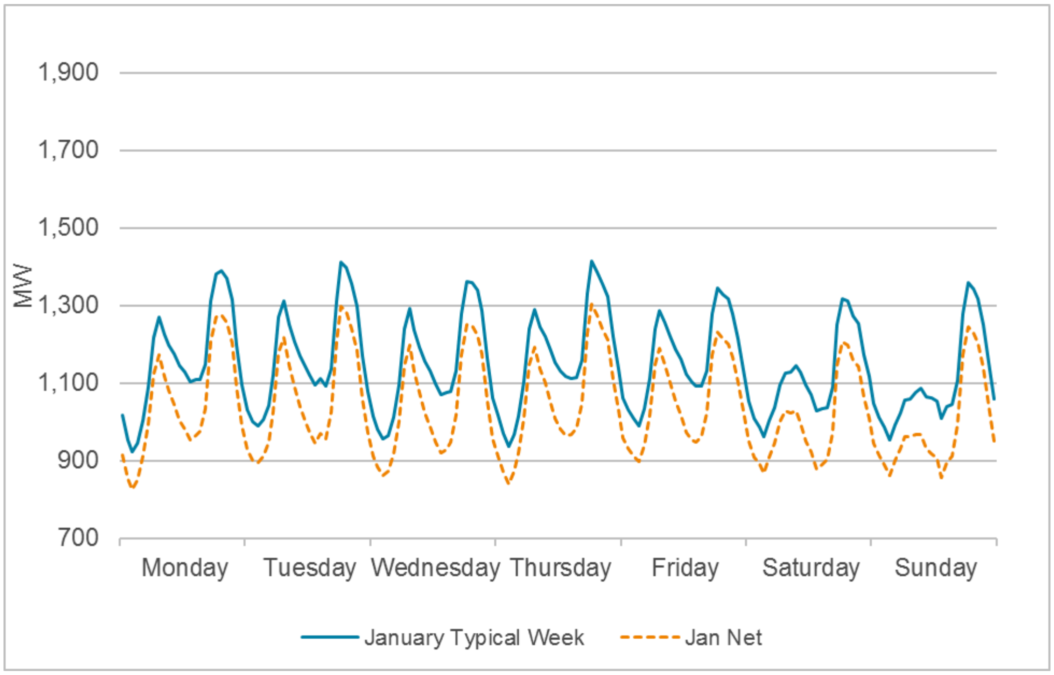


Figure 6. April Load Profile: Typical Week

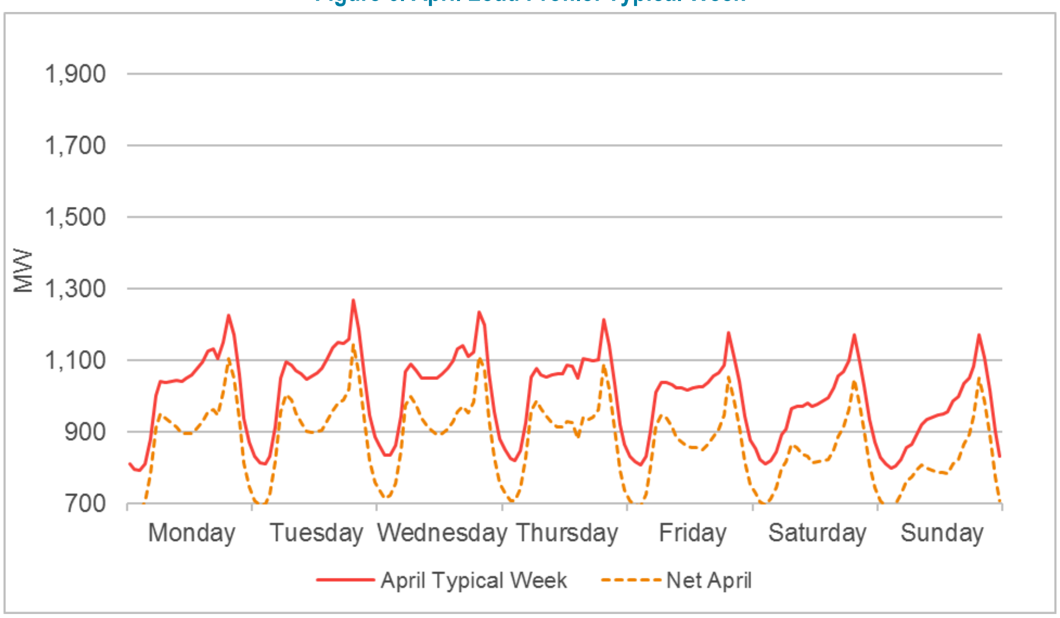


Figure 7. July Load Profile: Typical Week

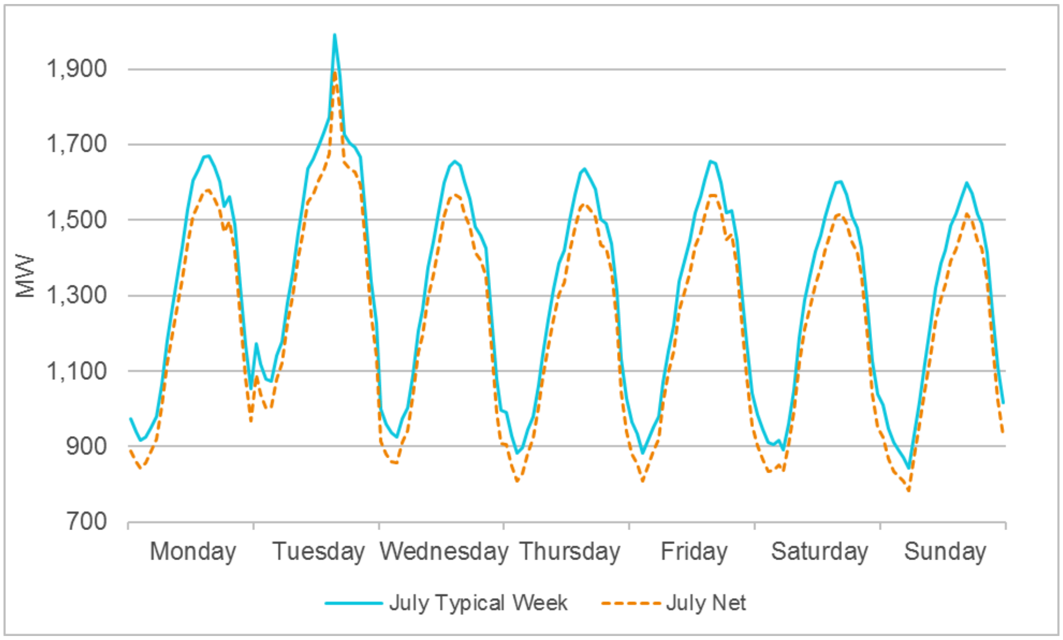
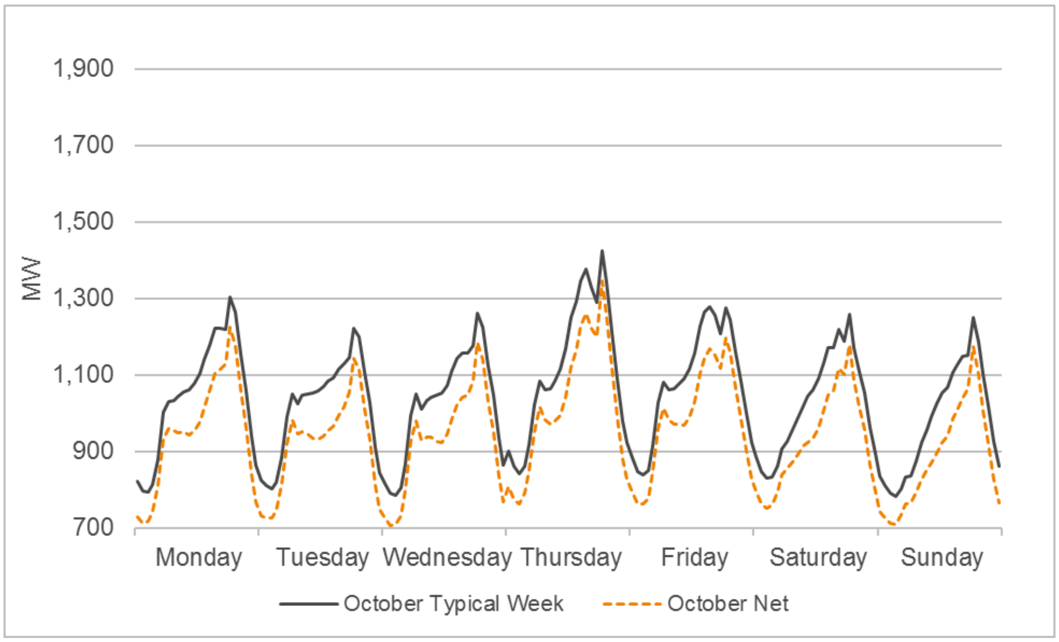


Figure 8. October Load Profile: Typical Week



APPENDIX B. ACRONYM LIST

APS: Arizona Public Service Company

Btu: British thermal unit

BA: Balancing Authority

CAA: Clean Air Act

CCN: Certificate of Convenience and Necessity

CO_2: Carbon dioxide

COP: Conferences of the Parties

DCS: Disturbance Control Standard

DG: Distributed Generation

DSM: Demand-Side Management

EGU: Electric Generating Unit

EPA: Environmental Protection Agency

EPRI: Electric Power Research Institute

EUEA: Efficient Use of Energy Act 62-17 NMSA

FCPP: Four Corners Power Plant

FERC: Federal Energy Regulatory Commission

GE: General Electric Company

GHG: Greenhouse Gas

GWh: Gigawatt-hour

IRP: Integrated Resource Plan

kW: Kilowatt, also shown as kW; a measure of capacity equal to 1,000 watts kWh: Kilowatt-hour, a measure or energy produced or consumed

lbs: Pounds

LOLE: Loss of load expectation

MCEP: Most cost-effective portfolio

MW: Megawatt

MWh: Megawatt-hour

NDCs: Nationally Determined Contributions

NDT: Nuclear Decomissioning Trust

NERC: North American Electric Reliability Council

NMAC: New Mexico Administrative Code

NMPRC: New Mexico Public Regulation Commission

NMWEC: New Mexico Wind Energy Center

NSPS: New Source Performance Standards

OATT: Open Access Transmission Tariff

Peak RC: WECC reliability coordinator

PPA: Power Purchase Agreement

PV: Photovoltaic

PVNGS: Palo Verde Nuclear Generating Station located near Phoenix, Arizona

REC: Renewable Energy Certificate

RFP: Request for Proposals

RGS: Reeves Generating Station

RPS: Renewable Portfolio Standard

SJGS: San Juan Generating Station located near Farmington, New Mexico

SPP: Southwest Power Pool

SRSG: Southwest Reserve Sharing Group

TAG: Technical Assessment Guide (by EPRI)

TEP: Tucson Electric Power Company

TOU: Time of Use

UNFCCC: United Nations Framework Convention on Climate Change

WACC: Weighted Average Cost of Capital

WECC: Western Electricity Coordinating Council

APPENDIX C. GLOSSARY OF IRP TERMINOLOGY

95th percentile: A value on a scale of 100 that indicates the percent of a distribution that is equal to or below 95% of the distribution (also referred to as the *upper tail*)

ACE Diversity Interchange: Power system control areas within three major (and essentially separate) areas of North America are interconnected electrically, thus enjoying vastly improved reliability and economy of operation compared to operating in isolation. Each must continually balance load, interchange, and generation to minimize adverse influence on neighboring control areas and interconnection frequency. This requires investment in control systems and the sacrifice of some fuel conversion efficiencies to achieve the objective of complying with minimum control performance standards set by the North American Electric Reliability Council (NERC). Control also increases wear and tear on machinery in the pursuit of these goals. Area control area (ACE) and area diversity interchange (ADI) offer a means of reducing this control burden without undue investment or sacrifice by any participant in a group. (Source: IEEE, http: //ieeexplore.ieee.org/Xplore/login.jsp?url=/iel1/59/8797/00387953.pdf?arnumber=387953)

Aeroderivative: A type of gas turbine for electrical power generation

Availability factor: The ratio of the time a generating facility is available to produce energy at its rated capacity, to the total amount of time in the period being measured, as defined by the IRP Rule

Avoided costs: The incremental cost to a utility for capacity and/or energy that could be avoided if another incremental resource addition such as energy efficiency were added that deferred or eliminated the need for the original addition

Base load: A resource that is most economically used by running at a capacity factor of 65% or greater on an annual basis. *See also* capacity factor.

Biomass resource: As defined by the IRP Rule, a recognized renewable resource type that uses renewable fuels such as agriculture or animal waste, small diameter timber, salt cedar and other phreatophyte or woody vegetation removed from river basins or watersheds, landfill gas and anaerobically digested waste biomass. *See also* renewable energy

Biomass Study: PNM Biomass Assessment: Status Report

Cap and trade: A regulatory body sets a cap on emissions of a designated pollutant, and sells permits equivalent to a firm's emissions. Firms that need to increase their emission permits must buy them from those who require fewer permits.

Capacity factor: Actual energy generated over a certain time period divided by theoretical ability to generate electricity over that same time period. Capacity factor is most often referenced as an annual calculation.

Capacity uprate: The maximum power level at which a nuclear power plant may operate

Carbon dioxide: Carbon dioxide (CO_2) is an important greenhouse gas because it is thought to contribute to global warming. An NMPRC Order in Case No. 06-00448-UT requires that electric utilities use the following standardized prices for carbon emissions in their IRP filing: $8, $20, and $40 per metric ton for their low, medium, and high price sensitivities, respectively. Currently, there is no emission allowance cost for CO2.

Centralized solar: Thermal solar facility that concentrates sunlight to collect heat and uses that heat to create steam that then drives a steam turbine to create electric generation (also referred to as *concentrating solar*)

Climate change: A significant change in measures of climate, including temperature, precipitation, or wind, that lasts for an extended period of time, resulting from natural factors or human activities that change the atmosphere's composition and the land surface

Combined cycle gas turbine: For electric generation, *combined cycle* refers to a gas turbine that generates electricity and heat in the exhaust used to make steam, which then drives a steam turbine to generate additional electricity.

Constrained transmission: A transmission system that can no longer accommodate additional capacity to meet demand is constrained.

Conventional resources: Coal, nuclear, hydro and natural gas resources that have historically been the most commonly used to supply electricity (also referred to as *traditional resources*)

Cost of Capital: The cost of financing utility plant investment, including interest on debt funding and return on equity funding.

Crediting: A billing mechanism that credits distribution generation system owners for electricity they add to the grid. When a home or business is net-metered, electricity generated is credited against what electricity is consumed when the home or business electricity use exceeds the system's output. Customers are only billed for their "net" energy use.

Demand response (DR) : A resource comprising programs that compensate electricity users in exchange for the ability to interrupt or reduce their electric consumption when system demand is particularly high and/or system reliability is at risk.

Demand: Usage at a point in time, measured in MW or kW

Demand-side resources: As defined by the IRP Rule, energy efficiency, and load management, as those terms are defined in the Efficient Use of Energy Act

Dispatchability: The ability of a generating unit to increase or decrease generation, or to be brought online or shut down at the request of a utility's system operator

Distributed generation: Electric generation that is sited at a customer's premises, providing energy to the customer load at that site and/or providing electric energy for use by multiple customers in contiguous distribution substation areas. In this report, it refers to PNM customer-sited, renewable, distributed generation program for solar photovoltaic systems less than 10 kilowatts in size.

Duty cycle: Generating facility design that determines how a facility is operated. Duty Cycle classifications are baseload, intermediate, or peaking.

EE Rule: Energy Efficiency Rule (17.7.2 New Mexico Administrative Code)

Emergency energy: Energy purchases to meet unserved load

Energy efficiency: Measures, including energy conservation measures or programs that target consumer behavior, equipment, or devices to result in a decrease in consumption of electricity without reducing the amount or quality of energy services, as defined by the IRP Rule

Energy: Usage over a period of time, measured in GWh, MWh, or kWh

Equivalent availability: Typically referred to as *Equivalent Availability Factor* (*EAF*), the proportion of hours in a given time period that a resource is available to generate at full capacity

Financial risk: Expected cost to the customer and the variability and uncertainty of future cost outcomes.

Fixed cost: Costs that are independent of output. *Contrast* variable costs.

Forced outage rate: Percentage of time a unit is not operational when it is expected to be in service

Geothermal Study: Geothermal Resource Development Needs in New Mexico

Geothermal: Electric generation fueled by heat from geologic formations, which qualifies as a renewable resource under 17.9.572 NMAC

Heat rate: The ratio of energy inputs used by a generating facility expressed in BTUs (British Thermal Units) to the energy output of that facility expressed in kilowatt-hours, as defined by the IRP Rule

Intermediate: A resource that is most economically run at capacity factors between 20% and 65% of the time on an annual basis. *See also* capacity factor.

IPP: Independent Power Producer – third party producers who sell capacity and/or energy to utilities.

Global Energy Partners Potential Study: Public Service New Mexico Electric Energy Efficiency Potential Study, dated June 30, 2011

IRP Rule: Integrated Resource Plan for Electric Utilities, NMPRC Rule 17.7.3 New Mexico Administrative Code (17.7.3 NMAC).

Jurisdictional load: Case 3137 Order identifies jurisdictional load as New Mexico retail load and wholesale firm requirement customers contracted prior to September 2, 2002.

Load duration curve: Illustration of the relationship between generating capacity requirements and capacity utilization. The load duration curve helps determine which type of resource best matches system load requirements.

Loads and Resources: A loads and resources table shows annual balance between load and the resources to meet the load, and includes the reserve margin calculation

Load factor: Average demand divided by peak demand

Load forecasting: The prediction of the demand for electricity over the planning period for the utility, as defined by the IRP Rule

Load management: Measures or programs that target equipment or devices to decrease peak electricity demand or shift demand from peak to off-peak periods, as defined by the IRP Rule

Load-following resource: This resource has a response rate that can meet normal fluctuations in load.

Loss of Load Expectation: expected number of firm load shed events in a given year

Loss of load probability: Percent of time load is not served

Marginal cost: The highest system resource cost for the hour

Mean: The expected value of a random variable (of a probability distribution), which is also called the *population mean*

Monte Carlo: Risk analysis technique utilizing multiple iterations calculated using random draws for sensitivity variables from a defined distribution for the variables

Most cost-effective resource portfolio: Those supply-side resources and demand-side resources that minimize the net present value of revenue requirements proposed by the utility to meet electric system demand during the planning period consistent with reliability and risk considerations, as defined by the IRP Rule

Nameplate capacity: The rated output of an electrical generator; it can also refer to the rated capacity of a power plant.

Net present value: The difference between the present values of cash inflows and the present value of cash outflows

Network transmission service: The transmission of capacity and energy from network generating resources to PNM's load.

Non-spinning reserves: The extra generating capacity that is not currently connected to the system, but can become available after a short delay

Particulate matter: A complex mix of extremely small particles and liquid droplets, including acids, organic chemicals, metals, and soil and dust, creating particle pollution

Peak demand: Occurs when demand for energy is at its greatest

Peak shaving: A strategy used to reduce electricity use during times of peak demand, typically employed through demand response programs

Peaking: A resource that is most economically run at a capacity factor of less than 20%. See also *capacity factor*

Photovoltaic solar: Solar generation that uses photovoltaic panels to convert sunlight directly to energy

Planning period: The future period for which a utility develops its IRP. For purposes of this rule, the planning period is 20 years, from 2014–2033.

Plug-in hybrids: Hybrid automobiles whose batteries are recharged by plugging into an electric socket

Point-to-point transmission service: Delivery of power from one location to another, without branching to other locations

Portfolio: A combination of resource additions/assets over the planning period that meet the reserve margin criteria

Private Solar: Solar energy that is used to offset an individual customer's utility bill (net metering).

Probability distribution: Describes the likelihood of a random parameter over a range of possible values

Public utility: As defined by the IRP Rule, public utility or utility has the same meaning as in the Public Utility Act, except that it does not include a distribution cooperative utility, as defined in the Efficient Use of Energy Act

Qualifying facilities: FERC established a new class of generating facilities that would receive special rate and regulatory treatment to support implementation of the Public Utility Regulatory Policies Act of 1978. Generating facilities fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities.

Rankine cycle: A heat engine with a vapor power cycle commonly found in power plants

Rate rider: According to State Statute 62-3-3-H, "Rate" means every rate, tariff, charge, or other compensation for utility service rendered or to be rendered by a utility and every rule, regulation, practice, act, requirement, or privilege in any way relating to such rate, tariff, charge, or other compensation and any schedule or tariff or part of a schedule or tariff thereof.

Reasonable Cost Threshold: is a customer protection mechanism that limits the customer bill impact resulting from renewable energy procurements by utilities. It is the cost level established by the Commission above which a public utility shall not be required to add renewable energy to its electric energy supply portfolio pursuant to the renewable portfolio standard.

Regional Entity: According to NERC, "NERC works with eight regional entities to improve the reliability of the bulk power system. The members of the regional entities come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico."

Regional haze: According to the EPA, regional haze is visibility impairment that is produced by activity that emits fine particles and their precursors over a geographic area.

Reliability: The ability of the electric system to supply the demand and energy requirements of the customers when needed and to withstand sudden disturbances

Renewable energy: As defined by the IRP Rule, electrical energy generated by means of a low or zero emissions generation technology with substantial long-term production potential and generated by use of renewable energy resources that may include solar, wind, hydropower, geothermal, fuel cells that are not fossil fueled, and biomass resources. See *biomass resource*

Renewable Energy Procurement Plan (REPP): PNM annual filing at the NMPRC that discusses plans to meet the Renewable Portfolio Standard set by the NMPRC.

Renewable resources: Generation resources that are based on a renewable fuel supply

Retail sales: The sale of energy to end users

Risk plot: The process of transposing a distribution histogram by measuring the mean and the 95th percentile and plotting the mean on the x-axis and the 95th percentile on the y-axis

Scenario: A combination of sensitivity values used to generate portfolios

Sensitivity: A variable that has a significant impact on risk evaluation

Solar: Electric generation fueled directly by sunlight

Solar hybrid: A thermal solar facility with the ability to supplement heat from the sun with heat derived by burning natural gas

Spinning reserves: Backup energy production capacity that can be available to a transmission system within 10 minutes and can operate continuously for at least two hours after being brought online

Spot prices: The price quoted for immediate settlement (payment) of a commodity

Stochastic analysis: Stochastic financial risk analysis

Strategist®: The resource portfolio modeling software that PNM uses for resource plan optimization. Strategist® is a registered trademark of Ventyx.

Total system costs: Total sum of annual costs for meeting the system's energy requirements with all resources

Universal Solar: Solar resources which are part of a utility's total generation supply used to serve all customers.

Upper tail: A value on a scale of 100 that indicates the percentage of a distribution that is equal to or below 95% of the distribution (also referred to as *95th percentile*)

Tri-State: Tri-State Generation and Transmission cooperative

Valencia: Valencia Generation Facility located near Belen, New Mexico

Variable costs: Costs that change with unit output. *Contrast* fixed costs

Water intensity: A measure of the water resource needed to generate over a defined period

Wheeling: Transportation of electric power over transmission lines

Wind: Electric generation fueled by wind turbines

APPENDIX D. DETAILED EXPLANATION OF PRIMARY MCEP STANDARDS

This appendix provides a detailed explanation of the three primary MCEP standards for PNM's BA discussed in the Planning Considerations Section under Operating Reserves.

BAL-002-1

BAL-002-1 is the Disturbance Control Performance Standard which sets requirements to restore supply and demand balance in the event of a system disturbance. It defines the allowable recovery period and the requirement to establish new reserves following a disturbance. To ensure compliance, PNM must maintain contingency reserves, which are resources under PNM's control that can be activated to respond to Disturbance Control Standard (DCS) events within the required time periods. An example of a typical DCS event would be the loss of a BA's single largest hazard. If PNM does not comply with these standards, not only can monetary penalties be assessed, but PNM is also exposed to a load-shed directive from WECC's Peak Regional Coordinator (RC), who monitors system reliability across WECC. System recovery is required to occur within 15 minutes and reserves must be restored within 60 minutes.

Within the 15-minute DCS recovery period, the first five minutes is when the BA conducts the following activities:

- Call and activate non-spinning reserves, which must be available within 10 minutes.
- Verify that PNM is receiving assistance from its reserve sharing group
- Activate any hazard share agreements

The remaining 10 minutes of the DCS reserve recovery period allow for spinning and non-spinning units to ramp up to their 10-minute delivery capability. At the end of the 15-minute recovery period, PNM's area control error must return to zero or to the precontingency value or bring supply into balance with the load.

Theoretically, PNM could meet these requirements through power purchases or sales; because of time and other constraints, PNM cannot practically depend upon market purchases to comply with the 15-minute DCS recovery requirement. These constraints include the following:

- Uncertainty as to whether counter parties will be willing to reduce their reserve margins intrahour
- The time required to contact potential counterparties to determine the availability and/or deliverability of an intrahour market power transaction
- The time required to negotiate an energy purchase once the availability and deliverability of the power is confirmed.
- The complexity of determining deliverability, which requires consideration of the following:

- Identification of transmission constraints from the point of receipt to the point of delivery (e.g., at Palo Verde, Four Corners, or San Juan)
- Intrahour scheduling and tagging constraints. For the BA's to agree to an intrahour interchange transaction, the electronic e-tag that is submitted has to be deemed an emergency for the receiving balance authority. WECC allows a 60-minute period for an emergency tag submittal for transfer of energy between balancing authorities; however, the process to implement such a transaction requires additional inter-company communications for verification, which can further delay the recovery.
- Time of year and day; during high load periods such as third quarter (July, August, and September) and the peak hours of the day, counterparties may not have excess energy to sell or generation units available to bring online
- Weather and loads in the WECC; when PNM is experiencing peak loads because of extreme temperatures, surrounding balance authorities are likely to be experiencing the same conditions and system stresses

In addition to the practical issues with relying upon market purchases and sales for system reliability that exist today, an observed recent loss of market liquidity and depth must factor into PNM's plans for a reliable resource portfolio. Market depth refers to the number of counterparties that are actively buying and selling in the day-ahead and hour-ahead markets. Market liquidity refers to the same concept but, in addition, also refers to the amount of power that counterparties are willing to transact (i.e., sell or purchase).

Market liquidity and depth have declined over time. The following factors have contributed to the loss of market liquidity and depth:

- Retirement of base load units throughout the western United States
- Market power concerns by some market entities
- Entry into the California Energy Imbalance Market by some entities
- More stringent gas scheduling requirements on interstate gas pipelines
- More stringent electricity scheduling rules
- FERC rules requiring designation/undesignation of resources
- Scheduling and tagging constraints across the scheduling hour
- Smaller differences between system incremental costs caused by newer gas units being on the margin
- Time of year and day (as discussed above)
- Weather and loads in the WECC (as discussed above)
- Ability for a natural gas generator to acquire intra-day gas supply and transportation
- Transmission availability to schedule the purchased power to PNM's load
- Scarcity of gas storage

There is much less market depth and liquidity in the real-time and day-ahead markets at the Four Corners and San Juan trading hubs than in the past, and the market situation is unlikely to improve because of planned generation retirements in the Four Corners region. There are fewer willing counterparties today; in most cases, when a counterparty is willing to enter into a transaction, the amount of energy offered is significantly less than in the past.

For these reasons, PNM does not plan on intrahour market purchases and is not a viable resource option for complying with the requirements for DCS reserve recovery or other reliability requirements.

BAL-002-WECC-2

As PNM adds more variable energy supplies to the system, PNM must consider the need to provide the requisite regulating reserves (i.e., ancillary services and flexibility) to maintain reliability as generation from the new resources ramps up and down. Increased intermittent generation on PNM's system has increased the fluctuations of generation output on the system. This also increases the need for quick-response solutions.

Contingency reserves are comprised of spinning and non-spinning reserves; spinning reserves must constitute at least 50% of the required amount of contingency reserves. Spinning reserves are the portion of reserves that the utility can call upon to immediately respond to a system disturbance. Spinning reserves include the following:

- PNM-controlled generation or storage resources that are online and synchronized to the BA's system so they can be accessed immediately to provide power to the system
- Market-based products (spin capacity) that are available to be called upon within the required recovery period (e.g., a generator located in another electric utility's system)

Market-based products for spin capacity are agreements with other entities for capacity and/or energy that can be called upon to assist PNM in responding to, and recovering from, a DCS event, re-establishing contingency reserves, and replacing lost generation to meet PNM's load service obligations. Market solutions mitigate, to the extent that they are available, the need for PNM to invest in new generation to comply with NERC and WECC standards. Use of these products requires PNM to maintain sufficient transmission capacity to utilize the agreements within the timeframes needed. Two market solutions for management of and recovery from DCS events include the following:

- **Southwest Reserve Sharing Group (SRSG) participation:** PNM is a participant in SRSG and benefits from sharing contingent reserves, thereby reducing NERC and WECC compliance costs
- **Hazard share agreement:** PNM is currently pursuing a 100 MW hazard share agreement with Tri-State that will improve PNM's ability to meet DCS recovery and contingency reserve restoration requirements at little or no cost. A hazard share agreement is between two generator owners that agree to share the risks of a generator loss by providing immediate assistance to each other in the event of the loss of the named resource.

SRSG is comprised of 15 southwestern utilities and registered under NERC. SRSG administers NERC compliance requirements for certain reliability standards including BAL-002, the DCS for utilities in the WECC region. This standard establishes the criteria and reporting requirements to ensure that an area BA, such as PNM, restores the electricity supply and demand balance within prescribed time limits following a reportable system disturbance. SRSG participants share contingency reserves to maximize generator dispatch efficiency, reduce the costs of compliance with the DCS, and enhance electric reliability. The SRSG geographical area covers Arizona, New Mexico, southern Nevada, parts of southern California including the Imperial Valley, and El Paso, Texas.

Similar to planning reserves, an adequate level of regulating reserves can be determined by considering loss of load probability (LOLP). The BAL-002-WECC-2 Standard establishes the minimum LOLP level, and PNM must remain in compliance with the minimum standards. Load and generation can vary quickly throughout the day, so PNM maintains a margin over the minimum standard to ensure continuous compliance. The minimum margin that PNM should carry is affected by the frequency and magnitude of sudden changes in the supply and demand balance. PNM has studied the relationship between the cost to carry regulating reserves and the probability of not having enough regulating reserves to respond to events that cause load or generation to suddenly change. Findings of this study follow:

- The need for flexible capacity is driven by short duration fluctuations in the supply demand balance (e.g., if a cloud floats over a PV solar generator, the change in generation is instant, but the associated change in demand from reduced household cooling needs will take longer to occur)
- Because loss of generation events typically are of short notice and duration, spinning reserves are more valuable as a supply of regulating reserves than non-spinning reserves

Non-spinning reserves are resources that are not online and synchronized to the balance authority’s system, but that are available to respond to system disturbances within a 10-minute period. There are many types of non-spinning reserves, including the following:

- Offline generation capable of ramping up and synchronizing to the grid within 10 minutes. PNM’s 10-minute available generating units include the two Lordsburg LM6000 units, the La Luz LM6000 unit, and the Rio Bravo Frame-7 unit on fuel oil.
- Shared contingency reserves, which PNM can access as a participant in the SRSG. Participants in SRSG share contingency reserves to maximize generator dispatch efficiency. SRSG assistance is provided for 60 minutes after the system disturbance. Shared reserves decrease the costs of compliance with the DCS standards and contribute to electric reliability in the Western Interconnection.
- Interruptible (Non-Firm) Interchange Transactions under which PNM’s sales to a counterparty can be recalled within 10 minutes to provide contingency reserves.
- Hazard sharing agreements with one or more external balancing authorities or with other generators within another balancing authority’s area.
- Demand response management actions to remove load from the system within the disturbance recovery period. An example of this mechanism would be the demand

response contracts that PNM has with Comverge and Enernoc. These contracts run June through September, with varying amounts of capacity available on weekdays between the hours of 1:00 p.m. and 8:00 p.m. for Comverge and 8:00 a.m. and 8:00 p.m. for Enernoc.

- Generator-based PPA or market purchases that can be delivered within the DCS recovery period.

PNM can use spinning reserves that exceed the spinning reserve requirement to meet the non-spinning contingency reserve requirement.

Standard energy purchases do not directly provide ancillary services such as spin, non-spin and frequency response. If available, market purchases can provide PNM the ability to ramp down its generation or take it offline to create contingency reserves. But, given the future uncertainty of availability, market purchases are not a reliable means of meeting the contingency reserves requirement.

Under the BAL-002-WECC-2 standard, once reserves are activated to recover from a DCS event, those reserves must be restored within 60 minutes. Noncompliance with the standard can result in a directive by the Peak RC to shed load. Restoring reserves allows PNM to accomplish a timely recovery from another DCS event should one occur.

BAL-003-1

NERC Standard BAL-003-1 is the Frequency Response Requirement. PNM, in its role as a BA, is required to have sufficient frequency response capability to maintain interconnection frequency within predefined boundaries by arresting frequency deviations and supporting frequency until the system's frequency is restored to its scheduled value.

APPENDIX E. TRANSMISSION FACILITIES

Table 10, Table 11, and Table 12 provide lists of PNM's existing transmission facilities.

Table 10. Existing Transmission Switching Stations

Name	Voltage Levels	Operator if Jointly Owned
Artesia	345	EPE
Alamogordo	115	PNM
Algodones	115	
Ambrosia	230, 115	
Amrad	345, 115	EPE
BA	345, 115	
Belen	115	
Bisti	230	
Blackwater	345	
Britton	115	
Corrales Bluffs	115	
Clines Corners	345	
El Cerro	115	
Embudo	115	
Four Corners	500, 345, 230	APS
Gallegos	230, 115	
Greenlee	345	TEP
Guadalupe	345	
Hidalgo	345	EPE (345), PNM (115)
Irving	115	
Kirtland	115	
Kyrene	500	SRP
Los Morros	115	
Lordsburg	115	
Luna	345, 115	EPE (345), PNM (115)
McKinley	345	TEP
MD1	115	
Mimbres	115	
Misson	115	
North	115	
Norton	115	
Ojo	345, 115	
Picacho	115	EPE
Pachman	115	
Palo Verde	500	SRP
Person	115	
Pillar	230	
Prager	115	
Red Mesa	115	
Reeves	115	
Rio Puerco	345, 115	

Name	Voltage Levels	Operator if Jointly Owned
San Juan	345, 230	
Sandia	345, 115	
Scenic	115	
Shiprock	345	WAPA
Snow Vista	115	
Springerville	345	TEP
Taiban Mesa	345	
Tome	115	
Turquoise	115	
Valencia	115	
Veranda	115	
West Mesa	345, 230, 115	
West Wing	500	SRP
Yah-Ta-Hey	115	
Zia	115	

Table 11. Existing Transmission Lines

Line Code	Voltage	From-To Switching Station Names or Substation Name if Tap Line
AA	115	Arriba Tap (VS Line)
AB	115	Reeves-BA (East Circuit)
AC	115	Alamogordo - Carrizo (TSGT)
AF	230	Pillar-Four Corners
AH	115	Alamogordo - Holloman (EPE)
AL	115	Pachman - Algodones
ANZ	115	Norton-Zia
ANZ	115	Algodones to 3-way switch
AR	115	Alamogordo - Amrad
AT	115	Person-El Cerro
AV	115	Avila Tap (RB Line)
AW	115	Algodones - Britton
AY	115	Ambrosia -Yah-Ta-Hey
BA	115	Bel Air Tap (HW Line)
BB	345	BA - Guadalupe
BI	230	Ambrosia -Bisti
BJ	345	Rio Puerco - West Mesa
BP	230	Bisti - Pillar
BW	115	Bluewater (TSGT) - West Mesa
CB	115	BA - Pachman
CE	115	Pachman - Scenic
CG	115	PN-HW Lines (Albuquerque Tie)
CM	115	Church Rock Tap (AY Line)
CN	115	Cornell Tap
CQ	115	Coal Tap
CS	115	Corrales Bluffs - Sara 1 & 2
CT	115	Corrales Bluffs - Sara 3 & 4 Substation
CY	115	Pachman - Corrales Bluff
DL	115	Mimbres - Picacho
DM	115	Mimbres - Deming 1 and 2 (TSGT Line)
EB	115	Embudo - Sandia

Line Code	Voltage	From-To Switching Station Names or Substation Name if Tap Line
EG	115	East Gallup Tap (AY Line)
EJ	115	Embudo - Juan Tabo Sub
ER	115	Embudo -Reeves
ES	115	El Dorado Tap (SL Line)
ET	115	Eastridge Tap (SE Line)
FC	345	San Juan - Four Corners
FW	345	Four Corners - West Mesa
GC	230	Gallegos - Pillar
HG	115	Hollywood - Gavilan
HO	115	Hernandez (TSGT) - Ojo
HR	115	Hidalgo - Turquoise
HW	115	EB-SP Line (Albuquerque Tie)
IC	115	Irving - Corrales Bluffs
IR	115	Irving - Reeves
JA	115	Jarrales Tap
KA	115	Kirtland - USAF
KB	115	Kirtland - Sandia Lab (KAFB)
KC	115	Marquez Tap (KM Line)
KD	115	Kirtland - Sandia Labs Area 5 (SNL)
KM	115	West Mesa - Red Mesa
KS	115	Kirtland - Sandia
LB	115	Lordsburg - Hidalgo
LK	115	Luna - Kenecott Tap
LL	345	Luna Station - Luna Energy Facility
LO	115	Lost Horizon Tap
LS	115	San Lucas Tap (KM Line)
LT	115	Leyendecker Tap (TL Line)
LU	115	Lenkurt Tap (EB Line)
LW	115	Lawrence Tap (SE Line)
MA	115	Red Mesa - Ambrosia
MB	115	Ambrosia -Bluewater (TSGT)
MH	115	MD1 - Ivanhoe Sub (Phelps Dodge)
MI	115	Miguel Lujan Tap (NS Line)
ML	115	Mimbres - Luna
MN	115	North-Mission
MP	115	Montano Tap (NP Line)
MR	115	MD1 - Turquoise
MT	115	Menual Tap (EB Line)
MW	115	Mimbres - Hermanas - Hondale
NB	345	Norton - BA
NH	115	Norton - Hernandez (TSGT)
NL	115	Norton - ETA (DOE)
NO	115	Noe Tap (Gallup) (EG Line)
NR	115	Reeves - Mission
NS	115	Norton - Zia
NW	115	West Mesa - Reeves
OJ	345	San Juan - Ojo
PA	115	Studio Tap (PS Line)
PL	115	Lomas Tap (PN Line)
PM	115	Person - West Mesa
PN	115	North - Prager
PR	115	Pachman - Progress Sub

Line Code	Voltage	From-To Switching Station Names or Substation Name if Tap Line
PS	115	Person - Kirtland
PV	115	Rio Puerco - Veranda
PW	115	Person-Snow Vista
RB	115	Reeves - BA (West Circuit)
RE	115	Reeves - Embudo
RL	115	BA - STA (STA Owned by LANL)
RN	115	Reeves - North
RR	115	Veranda - Corrales Bluff
RS	115	BA - Zia
SE	115	Sandia - Embudo
SG	115	Signetics Tap (AB Line)
SK	115	West Mesa-Scenic
SL	115	Zia - Valencia
SP	115	Sandia - Person
SR	345	San Juan - Shiprock
ST	115	San Pedro - I-40 (Albuquerque Tie)
TB	345	Taiban Mesa - Blackwater
TC	115	Tome-El Cerro
TG	345	Taiban Mesa - Guadalupe
TJ	115	Tome - Belen
TL	115	North - Lyendecker (EB Line)
TR	115	Truman Tap (SP Line)
TV	115	Tome - Valencia Energy Facility (Blackhills)
TW	115	Britton-Willard (TSGT)
TY	115	Turquoise - Tyrone Sub (Phelps Dodge)
UT	115	University Tap (HW Line)
VS	115	Valencia - Storrie Lake (TSGT)
WA	230	West Mesa - Ambrosia
WB	115	Belen-Los Morros
WC	115	Wesmeco Tap (SP Line)
WD	115	West Mesa-Los Morros
WG	115	West Gallup Tap (AY Line)
WJ	115	West Mesa-Snow Vista
WL	115	Willard (TSGT) - Belen
WN	345	Rio Puerco - BA
WP	115	West Mesa - Prager
WR	115	West Mesa - Irving
WS	345	West Mesa - Sandia
WV	115	West Mesa - Volcano
WW	345	San Juan - BA
YN	115	Yah-Ta-Hey - Coalmine (NTUA)
YP	115	Yah-Ta-Hey - Pittsburg Midway Sub
ZF	115	Zia - South Pacheco
ZN	115	Mejia Tap (NZ Line)

Table 12: Existing Joint-Owned Transmission Lines

Line Code	Voltage	From-To Switching Station Name	Operator
	345	Amrad - Artesia	EPE
SJ-MC 1	345	San Juan - McKinley Line 1	TEP
SJ-MC 2	345	San Juan - McKinley Line 2	TEP
	345	McKinley - Springerville Line 1	TEP
	345	McKinley - Springerville Line 2	TEP
	345	Springerville - Greenlee	TEP
GH	345	Greenlee - Hidalgo	EPE
HL	345	Hidalgo - Luna	EPE
	500	Palo Verde - Westwing Line 1	SRP
	500	Palo Verde - Westwing Line 2	SRP
	500	Hassayampa - Jojoba - Kyrene	SRP

APPENDIX F. INTEGRATION OF VARIABLE ENERGY RESOURCES

In general, resource planning studies identify the most economical resource mix to meet a time varying load profile. However, the addition of renewables to the transmission grid adds challenges in regulating the electric system to balance resources with load because the output of most renewable resources can vary greatly over short periods of time. Traditional dispatchable thermal generation is challenged by growing requirements to accommodate large amounts of variable energy resources (VER).

In 2003, PNM interconnected its first significant VER (the 204 MW New Mexico Wind Energy Center) and quickly saw a jump in regulation requirements for system operations, particularly related to the regulation for moment-to-moment power fluctuations. This was compounded by the degradation of the instantaneous response capabilities of PNM's coal plants caused by increasing use of regional coal plants to serve as regulating resources as wind generation increased. Utilities have moved to limit coal plant use as regulating resources to maintain operating efficiency and to preserve future response capability.

Given the present situation and level of existing resources available for regulation and imbalance service, PNM is very near the limit of its ability to integrate additional VERs based upon the need to conform to NERC control performance standards.

PNM has limited regulating resources to provide the required regulation and frequency response service for additional VER capacity located within PNM's BA. By using dynamic scheduling, PNM substantially transfers the obligation for operating additional generation to regulate the VER when it is physically located within another BA. As of today, PNM has implemented dynamic scheduling for three wind farms rated at a total of 292 MW. However, the challenge remains regarding providing regulation for VERs for PNM's system and within the BA.

The integration of additional VER presents a lengthy set of challenges for the industry. The FERC, through its rulemaking process, is also looking for solutions. FERC has a VER rulemaking underway that proposes new forecasting, intrahour scheduling requirements, and ancillary pricing mechanisms.

Regional Initiatives

In addition to the use of dynamic scheduling to reduce its regulating burden, PNM has participated in several regional initiatives to address this issue. The following list provides the existing and proposed methods and initiatives for sharing a BA's regulating burden that PNM is exploring jointly with its regional utility neighbors.

Dynamic Scheduling

NM uses dynamic scheduling to reduce energy imbalances for PNM BA interconnected VERs selling output to an entity located within another BA. As a result, the utility in the receiving BA provides the regulation, load following, imbalance, and other ancillary service requirements. As such, VER integration costs are shifted to the renewable energy consumers. Once established, dynamic scheduling effectively creates a larger footprint for sharing the regulation burden of intermittent resources. Dynamic scheduling also avoids:

- Use of and wear-and-tear on the VER's host BA's existing limited regulation generating resources
- The need for a host BA to construct or purchase additional flexible response generating resources to provide regulation for third-party users as additional VERs are eventually interconnected in that BA

WECC Reliability Based Controls

WECC initiated the Reliability Based Control (RBC) Field Trial on March 2010 to maintain frequency and manage the Area Control Error (ACE). ACE is the difference between scheduled and actual electric generation while accounting for frequency bias within a control area. PNM joined the WECC RBC Field Trial in June 2011. The integration of VER can cause an increase in the frequency variation which may then contribute to ACE. Since the 1990s, Automatic Generation Control (AGC) systems have regulated ACE within limits prescribed by the Control Performance Standard (CPS) 2, mandated by NERC. The RBC is a proposed replacement for CPS2 that relaxes the limits on a BA's ACE when ACE is in a direction that helps the interconnection recover from a frequency variation, thereby reducing the impact of variable generation on control performance while also reducing wear and tear on regulating generators. To date, the RBC Field Trial has not had a significant adverse effect on interconnection frequency or transmission grid congestion.

Dynamic Scheduling System

Dynamic Scheduling System (DSS) is a joint initiative between Columbia Grid, Northern Tier Transmission Group, and WestConnect. DSS facilitates the dynamic transfer of energy through a common communication protocol infrastructure to allow quick setup of dynamic schedules, which currently can take months to implement. Instead of the months now required to implement current dynamic schedules, DSS will accomplish the same feat within minutes. Consistent with existing practices, bilateral transactions will still be established contractually between the buyer and seller irrespective of the DSS, but the terms of the agreement would be communicated via approved dynamic e-Tags using existing processes and practices. DSS provides participants access to one another's generation and resources, giving merchant and reliability entities a standard method to easily and quickly exchange commodities between balancing areas.

Regional Transmission Planning and Coordination Groups

Numerous organizations are involved in planning coordination of the western grid. Planning processes involve open dialog and opportunity for all stakeholders to have input into the development of PNM's transmission plans. In addition to the planning meetings that PNM sponsors twice per year, PNM also participates in the WECC Planning Coordination Committee, WECC Transmission Expansion Planning Policy Committee (TEPPC), WestConnect Planning Committee, and the Southwest Area Transmission Planning Oversight Committee (SWAT).

This is important to the IRP process because developments within WECC that affect PNM's transmission operations will have the potential to affect or influence future resource selections. PNM participates in these committees and transmission groups to stay informed and to protect the interests of the customers and company stockholders. New operating ideas or concepts start in small regions of the system and, as they are tested and evaluated, they are shared with neighboring utilities. It is important that PNM continues its participation because it allows the company to leverage lessons learned from others.

WECC Planning Committees

PNM is a member of WECC and its mission is to coordinate and promote electric system reliability. In addition, WECC works to support efficient competitive power markets, ensure open and nondiscriminatory transmission access, provide a forum for resolving transmission access disputes, and provide an environment for coordinating the operating and planning activities of the Western Interconnection. WECC is one of eight electric reliability councils in North America. Membership in WECC is open to all entities with an interest in the operation of the bulk electric system in the Western Interconnection.

PNM participates in the planning functions of WECC through the Planning Coordination Committee (PCC) and the Transmission Planning Policy Expansion Committee (TEPPC). PNM has membership in several of the PCC subcommittees and workgroups that focus in varying degrees on transmission planning and coordination activities.

Planning Coordination Committee

The PCC is chartered to do the following:

- Recommend criteria for the guidance of the members, for adequacy of power supply, and for such elements of system design that affect the reliability of the interconnected bulk power systems
- Accumulate necessary data and perform regional studies of the operation of the interconnected systems necessary to determine the reliability of the western regional bulk power network
- Evaluate proposed additions or alterations in facilities in relation to established reliability criteria
- Identify the types and investigate the impact of delay on the timing and availability of power generation and transmission facilities
- Review reports and recommendations prepared by subcommittees and others concerning reliability and adequacy of power supply and then forward reports or recommendations with comments and/or recommendations to the Board of Directors in a timely manner
- Prepare appropriate reports and maps of planning information for governmental regulatory agencies, reliability councils, and others, as required.

Transmission Expansion Planning Policy Committee

TEPPC's three main functions include: (1) overseeing database management (for economic modeling), (2) providing policy and management of the planning process, and (3) guiding the analyses and modeling for Western Interconnection economic transmission expansion planning. These functions complement, but do not replace, the responsibilities of WECC members and stakeholders to develop and implement specific expansion projects.

Membership in TEPPC is based on balanced representation designed to reflect the geographic and stakeholder breadth of WECC. TEPPC will include transmission providers, policymakers, governmental representatives, and others with expertise in planning, building new economic transmission, evaluating the economics of transmission or resource plans, or managing public planning processes. PNM participates in the TEPPC stakeholder meetings and is a member of the TEPPC Technical Advisory Subcommittee (TAS), which conducts the study work needed to support the TEPPC charter. TAS has work groups that support the models, data, and study assumptions being used in the TEPPC study program. At times, PNM participates in these work groups.

Other Coordination Groups

PNM has membership in several additional committees or coordination groups that more specifically focus on the southwest and New Mexico. These groups developed independently of WECC, but now have processes coordinated with WECC's committees. These include processes and policies resulting from legislation and FERC requirements seeking an open stakeholder process for planning and coordination on a regional basis. The main committees are listed below.

WestConnect

WestConnect is composed primarily of utility companies providing transmission of electricity in the southern portion of the Western Interconnection. Members work collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to the western wholesale electricity market. WestConnect is committed to coordinating its work with other regional industry efforts to achieve as much consistency as possible in the Western Interconnection. In 2007, WestConnect executed the WestConnect Project Agreement for Subregional Transmission Planning (STP Project Agreement), of which PNM is a signatory. The agreement establishes the terms for developing a coordinated transmission expansion plan within the WestConnect footprint that covers the desert southwest as well as utilities and stakeholders in Colorado, Wyoming, Nevada, and parts of California. The transmission studies are typically performed under one of the WestConnect STP groups and feed into the coordinated plan. PNM is a member of the SWAT STP group listed next.

Southwest Area Transmission Planning Oversight Committee

SWAT is comprised of transmission regulators/governmental entities, transmission users, transmission owners, transmission operators, and environmental entities. The goal of SWAT is to promote regional planning in the Desert Southwest. The SWAT regional planning group includes several subcommittees, which are overseen by the SWAT Oversight Committee. PNM chairs the New Mexico subcommittee of SWAT, which focuses on stakeholder coordination of transmission expansion among the utilities and market participants in New Mexico.

Other Transmission Planning Committees

PNM has established a Network Integration Transmission Customer Operating Committee that meets twice a year. The meetings are used to provide direct communications with PNM's network customers. The transmission system improvement needs within the PNM control area including PNM's transmission expansion plans are standard topics for discussion at these meetings.

From time to time, PNM participates in planning efforts where parties may wish to look at a common solution for multiple interests. Although these activities are not directly under the WECC or WestConnect committees, results of analyses and stakeholder input are frequently shared in WECC and WestConnect forums.

Southwest Variable Energy Resource Initiative (SVERI)

SVERI is a coalition of utilities in the desert southwest that was formed in the fall of 2012. The SVERI participants include Arizona Public Service Company, El Paso Electric, Imperial Irrigation District, Public Service Company of New Mexico, the Salt River Project, Tucson Electric Power, and the Desert Southwest region of the Western Area Power Administration.

SVERI’s mission is to evaluate likely penetration, locations, and operating characteristics of VERs within the Southwest subregion over the next 20 years. It explores tools that may facilitate VER integration and provide benefits to customers.

SVERI launched a dedicated website that provides near real-time data for renewable energy resources from across the desert Southwest and the net effect they have on load and other resources. The website is available to the public and can be accessed at http://sveri.uaren.org.

APPENDIX G. RULES AND REGULATIONS

Transmission System

Over the last 18 years, U.S. electric transmission service has undergone major regulatory changes in the way transmission services are offered and provided and how transmission system planning is conducted.

FERC Order No. 888

The largest change stems from the 1996 implementation of the FERC Order No. 888. This order requires that a jurisdictional transmission provider, such as PNM, provide open access for transmission capacity to all eligible customers via an Open Access Transmission Tariff (OATT or Tariff). Eligible customers (e.g., Tri-State Generation and Transmission on behalf of its cooperative members, and Los Alamos County) under the Tariff can contract for Network Integration Transmission Service (NITS) to integrate their designated network resources and designated network loads on the PNM transmission system in a manner comparable to how PNM serves its own retail and wholesale customers.

The order obligates PNM to plan its transmission system to meet not only its own retail customer needs, but also its delivery obligations to NITS and long-term, firm point-to-point transmission service customers. Tariff customers can also choose to contract for firm point-to-point transmission service on a long-term basis with rollover rights that are essentially perpetual.

Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPACT) legislated the implementation on a nationwide basis of mandatory transmission grid reliability rules for all owners, operators, and users of the systems. Under the EPACT, FERC was given authority to develop, monitor, and enforce all aspects of transmission grid reliability. FERC delegated to the North American Electric Reliability Corporation (NERC) the role of the national Electric Reliability Organization (ERO). The Western Electric Coordinating Council (WECC) has been delegated the role of the Regional Entity within North American Electric Reliability Corporation (NERC) that will monitor and enforce the mandatory reliability standards in the Western United States. Failing to comply with the ERO standards subjects a utility to sanctions and civil penalties of up to $1 million per day for each incident for the most substantive failures to follow FERC's grid reliability rules.

FERC Order No. 890

Issued in February 2007, after broader powers were delegated to FERC and NERC under the EPACT, this order clarified and strengthened these obligations initially established by Order No. 888 and required regional coordination by transmission companies of transmission system planning.

FERC Order No. 1000

FERC Order 1000, issued July, 21, 2011, expands the responsibilities for regional coordination in transmission system planning. Public utility transmission providers participate in a regional transmission planning process that evaluates transmission alternatives at the regional level in order to resolve the region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes. These processes must incorporate transmission needs driven by public policy requirements and result in a regional transmission plan. PNM participation in Order 1000 is through is participation in WestConnect, which started in 2015.

System Reliability Standards

PNM regards system reliability as an overarching consideration for selecting the most cost-effective resource portfolio. The following paragraphs review the system reliability standards required of PNM. As previously discussed, PNM's planning reserve margin target is set by NMPRC at the greater of 13% or 250 MW. In addition, PNM's planning reserve must consider operating requirements, loss of the largest load-side resource, including transmission, and forecast uncertainty due to normal forecast fluctuations and extreme weather. The combination of these factors is an approximate minimum reserve of 250 MW.

WECC and NERC Criteria

As a member of Western Electricity Coordinating Council (WECC) and North American Electric Reliability Council (NERC), PNM complies with reliability criteria to ensure that its electric systems are safely and reliably operated.

PNM must comply with NERC operating standards, which, in part, might dictate the use of certain resources to meet the requirements. These include Control Performance Standards[2] (CPS), which measure a control area operator's ability to control system frequency and balance its load and generation at all times. They also include Disturbance Control Standards[3], which measure the control area's ability to respond to generator or load loss.

PNM must also comply with NERC standards that relate to transmission planning and operations. These include Transmission Planning Standards[4] (TPL), which measure the sufficiency of the transmission system to meet present and future needs. TPL standards state that, "The interconnected power system shall be operated at all times so that general system instability, uncontrolled separation, cascading outages or voltage collapse will not occur as a result of any single contingency or multiple contingencies of sufficiently high likelihood."

Power Supply Assessment (PSA)

NERC requires WECC to annually evaluate future resource adequacy of the western region based upon annual resource plans submitted by member utilities. The PSA is a regional and subregional determination of resource adequacy, rather than an individual utility evaluation of resource adequacy. The purpose, as stated in the Reliability Assessment Guide book[5], is

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2 See BAL-001-0_1a.pdf
3 See BAL-002-1.pdf and BAL-002-WECC-1.pdf
4 See TPL-001-0.1 through TPL-004-0 standards
5 See Reliability Assessment Guidebook v1.2

“to project whether enough physical resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths.” PNM, balancing area coordinator (BAC) in New Mexico, participates in the PSA study process and collects historical and future load and resource information from load-serving entities (LSEs) within New Mexico. This assessment is important because, if the PSA were to identify a resource adequacy issue in the region or subregion where PNM operates, PNM would be obligated to participate in finding a solution to the resource deficiency.

Reserve Sharing Agreements

In addition to meeting planning criteria, PNM also ensures that its resource portfolio meets operating conditions. From time to time, the operation of PNM’s system may warrant additional generation or the use of certain types of reserves to maintain adequate stability.

PNM recognizes the economic and reliability benefits of participating in the Southwest Reserve Sharing Group (SRSG) for operating reserves. The operating reserve margin is measured in real time to maintain proper system frequency and balancing of loads to resources in the southwestern United States.

Southwestern U.S. utilities specify their load requirements and their resource availability on an hourly basis to SRSG. The SRSG administration examines the risk or the likelihood of a system disturbance to determine the collective reserves it needs to hold. SRSG then notifies each utility of the operational reserves they should hold, in addition to the resources each utility uses to serve its customers. Total SRSG operating reserves can be split between spinning reserves (coming from units that are operating at less than their full output) and non-spinning reserves (resources that are not operating, but can be brought online within 10 minutes). PNM’s participation in SRSG is critical to minimizing the expense of PNM’s reliability obligations. If PNM had to provide all of the necessary reserves itself, the requirement would equal its single largest operating unit, which is the utility’s largest risk.

PNM’s SRSG allocation is partly determined by the size of the units that are included in PNM’s operating portfolio. Currently, PNM’s single largest potential risk is SJGS Unit 4 (240 megawatts), if it is operating, or Afton (230 megawatts), if Afton is operating and SJGS Unit 4 is not. Looking forward, and for purposes of this IRP, PNM must determine how new resource additions might change the level of reserves required for SRSG purposes or otherwise result in additional costs to meet reliability standards. Generally, PNM’s planning criterion is to limit the size of new generation to that of the current largest unit.

Other System Reliability Standards

Although states have played the primary role in setting reserve margin requirements, federal agencies (Federal Energy Regulatory Commission [FERC] and NERC) have taken on increased responsibility. Numerous states (including Maryland, New Jersey, Pennsylvania, Ohio, Indiana, Wyoming, Delaware, and the District of Columbia, in addition to portions of Michigan, Wisconsin, Illinois, Kentucky, Tennessee, and Virginia) have received approval from FERC to utilize one-day-in-10-years resource planning criteria. Implementation of this criterion would result in planning for sufficient resources so that no more than 48 load hours would be lossed in a 20-year planning period. This is a more stringent criterion than PNM's existing reserve planning criteria, but could be a consideration for future planning.

IRP Rules

Table 13. IRP Rules Checklist

Rule Section	Reporting Requirement Checklist	Subject Section	Location
9.B.1	description of existing electric supply-side and demand-side resources	Overview	
9.B.2	current load forecast as described in this rule	Overview	
9.B.3	load and resources table	Overview	
9.B.4	identification of resource options	Overview	
9.B.5	description of the resource and fuel diversity	Overview	
9.B.6	identification of critical facilities susceptible to supply-source or other failures	Overview	
9.B.7	determination of the most cost effective resource portfolio and alternative portfolios	Overview	
9.B.8	description of public advisory process	Overview	
9.B.9	action plan	Overview	
9.B.10	other information that the utility finds may aid the commission in reviewing the utility's planning processes	Overview	
9.C.1	name(s) and location(s) of utility-owned generation facilities;	Description of existing resources	Table 14
9.C.2	rated capacity of utility-owned generation facilities;	Description of existing resources	Table 14
9.C.3	fuel type, heat rates, annual capacity factors and availability factors projected for utility-owned generation facilities over the planning period;	Description of existing resources	Table 14; Appendix J
9.C.4	cost information, including capital costs, fixed and variable operating and maintenance costs, fuel costs, and purchased power costs;	Description of existing resources	Appx J
9.C.5	existing generation facilities' expected retirement dates;	Description of existing resources	Appx J
9.C.6	amount of capacity obtained or to be obtained through existing purchased power contracts or agreements relied upon by the utility, including the fuel type, if known, and contract duration;	Description of existing resources	Table 21
9.C.7	estimated in-service dates for utility-owned generation facilities for which a certificate of public convenience and necessity (CCN) has been granted but which are not in-service	Description of existing resources	n/a
9.C.8	amount of capacity and, if applicable, energy, provided annually to the utility pursuant to wheeling agreements and the duration of such wheeling agreements;	Description of existing resources	Existing Transmission
9.C.9	description of existing demand-side resources, including (1) demand-side resources deployed at the time the IRP is filed; and (2) demand-side resources approved by the commission, but not yet deployed at the time the IRP is filed; information provided concerning existing demand-	Description of existing resources	Existing Demand-Side Resources

Rule Section	Reporting Requirement Checklist	Subject Section	Location
	side resources shall include, at a minimum, the expected remaining useful life of each demand-side resource and the energy savings and reductions in peak demand, as appropriate, made by the demand-side resource;		
9.C.10	reserve margin and reserve reliability requirements (e.g. FERC, power pool, etc.) with which the utility must comply and the methodology used to calculate its reserve margin	Planning Considerations and existing resources	Existing Transmission and Appendix D
9.C.11.a	the utility shall report its existing, and under-construction, transmission facilities of 115 kV and above, including associated switching stations and terminal facilities; the utility shall specifically identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of supply-side resources;	Planning Considerations and existing resources	Existing Transmission and Appendices D & E
9.C.11.b	the utility shall describe all transmission planning or coordination groups to which it is a party, including state and regional transmission groups, transmission companies, and coordinating councils with which the utility may be associated;	Planning Considerations and existing resources	Existing Transmission and Appendix D
9.C.12	environmental impacts of existing supply-side resources		
9.C.12.a	the utility shall provide the percentage of kilowatt-hours generated by each fuel used by the utility on its existing system, for the latest year for which such information is available	Customers	Table 2
9.C.12.b	to the extent feasible, for each existing supply-side resource on its system, the utility shall present emission rates (expressed in pounds emitted per kilowatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury	Planning Considerations	Table 8 and Appendix J
9.C.12.c	to the extent feasible, for each existing supply-side resource on its system, the utility shall present the water consumption rate	Description of existing resources	Appendix J
9.C.13	a summary of back-up fuel capabilities and options	Description of existing resources	Existing Thermal Resources
9.D.1	The utility shall provide a load forecast for each year of the planning period; the load forecast shall incorporate the following information and projections		
9.D.1.a	annual sales of energy and coincident peak demand on a system-wide basis, by customer class, and disaggregated among commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states	Customers	Appendix A
9.D.1.b	annual coincident peak system losses and the allocation of such losses to the transmission and distribution components of the system	Customers	Load Forecast and Appendix A
9.D.1.c	weather normalization adjustments	Customers	Load Forecast and Appendix A
9.D.1.d	assumptions for economic and demographic factors relied on in load forecasting	Customers	Load Forecast and Appendix A

Rule Section	Reporting Requirement Checklist	Subject Section	Location
9.D.1.e	expected capacity and energy impacts of existing and proposed demand-side resources	Customers	Load Forecast and Appendix A & N
9.D.1.f	typical historic day or week load patterns on a system-wide basis for each major customer class	Customers	Append A; n/a by customer class
9.D.2	The utility shall develop base-case, high-growth and low-growth forecasts, or an alternative forecast that provides an assessment of uncertainty (e.g., probabilistic techniques	Customers	Load Forecast and Appendix A
9.D.3.a	The utility shall explain how the demand-side savings attributable to actions other than the utility-sponsored demand-side resources for each major customer class are accounted for in the utility's load forecast and the effect, as appropriate, on its load forecast of the utility-sponsored demand-side resources on each major customer class	Customers	Load Forecast; Energy Efficiency
9.D.3.b	The utility shall compare the annual forecast of coincident peak demand and energy sales made by the utility to the actual coincident peak demand and energy sales experienced by the utility for the four years preceding the year in which the plan under consideration is filed. In addition, the utility shall compare the annual forecast in its most recently filed resource plan to the annual forecast in the current resource plan. In its initial IRP filing, the utility shall provide information demonstrating how well its forecasts during the preceding four years predicted demand	Customers	Appendix A
9.D.3.c	The utility shall explain and document the assumptions, methodologies, and any other inputs upon which it relied to develop its load forecast	Customers	Load Forecast and Appendix A
9.D.1	The utility shall provide a load forecast for each year of the planning period; the load forecast shall incorporate the following information and projections		
9.E.1	utility-owned generation	L&R Table	Appendix N
9.E.2	existing and future contracted-for purchased power including qualifying facility purchases	L&R Table	Appendix N
9.E.3	purchases through net metering programs, as appropriate	L&R Table	Appendix N
9.E.4	demand-side resources, as appropriate	L&R Table	Appendix N
9.E.5	other resources relied upon by the utility, such as pooling, wheeling, or coordination agreements effective at the time the plan is filed	L&R Table	Appendix N
9.F.1	In identifying additional resource options, the utility shall consider all feasible supply-side and demand-side resources. The utility shall describe in its plan those resources it evaluated for selection to its portfolio and the assumptions and methodologies used in evaluating its resource options, including, as applicable: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility and efficiency of the resource.	Potential Resource Additions	Appendix K

Rule Section	Reporting Requirement Checklist	Subject Section	Location
9.F.2	For supply-side resource options, the utility shall identify the assumptions actually used for capital costs, fixed and variable operating and maintenance costs, fuel costs forecast by year, and purchased power demand and energy charges forecast by year, fuel type, heat rates, annual capacity factors, availability factors and, to the extent feasible, emission rates (expressed in pounds emitted per kilowatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury	Potential Resource Additions	Appendix K
9.F.3	The utility shall describe its existing rates and tariffs that incorporate load management or load shifting concepts. The utility shall also describe how changes in rate design might assist in meeting, delaying or avoiding the need for new capacity	Customers; Description of Existing Resources;	Existing Demand-Side Resources
9.G.1	To identify the most cost-effective resource portfolio, utilities shall evaluate all feasible supply and demand-side resource options on a consistent and comparable basis, and take into consideration risk and uncertainty (including but not limited to financial, competitive, reliability, operational, fuel supply, price volatility and anticipated environmental regulation). The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis. The utility shall also consider and describe ways to mitigate ratepayer risk	Analysis Results; Determination of MCEP	Appendix L & M
9.G.2	Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios		
9.G.2.a	load management and energy efficiency requirements	Analysis Results; Determination of MCEP	Appendix L & M
9.G.2.b	renewable energy portfolio requirements	Analysis Results; Determination of MCEP	Appendix L & M
9.G.2.c	existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions	Analysis Results; Determination of MCEP	Appendix L & M
9.G.2.d	fuel diversity	Analysis Results; Determination of MCEP	Appendix L & M
9.G.2.e	susceptibility to fuel interdependencies	Analysis Results; Determination of MCEP	Appendix L & M
9.G.2.f	transmission constraints	Analysis Results; Determination of MCEP	Appendix L & M
9.G.2.g	system reliability and planning reserve margin requirements	Analysis Results; Determination of MCEP	Appendix L & M
9.G.3	Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop a reasonable number of alternative portfolios by altering risk assumptions and other parameters developed by the utility	Analysis Results; Determination of MCEP	Appendix L & M

Rule Section	Reporting Requirement Checklist	Subject Section	Location
	and the public advisory process.		
9.H.1	The utility shall initiate the process by providing notice at least 30 days prior to the first scheduled meeting to the commission, interveners in its most recent general rate case, and participants in its most recent renewable energy, energy efficiency and IRP proceedings; the utility shall at the same time, also publish this notice in a newspaper of general circulation in every county which it serves and in the utility's billing inserts	Public Advisory Process	
9.H.1.a	a brief description of the IRP process	Public Advisory Process	
9.H.1.b	time, date and location of the first meeting	Public Advisory Process	
9.H.1.c	a statement that interested individuals should notify the utility of their interest in participating in the process	Public Advisory Process	
9.H.1.d	utility contact information	Public Advisory Process	
9.H.2	Upon receipt of the initial notice, the commission may designate a facilitator to assist the participants with dispute resolution	Public Advisory Process	
9.H.3	The utility or its designee shall chair the public participation process, schedule meetings, and develop agendas for these meetings. With adequate notice to the utility, participants shall be allowed to place items on the agenda of public participation process meetings	Public Advisory Process	
9.H.4	Meetings held as part of the public participation process shall be noticed and scheduled on a regular basis and shall be open to members of the public who shall be heard and their input considered as part of the public participation process. Upon request, the utility shall provide an executive summary containing a non-technical description of its most recent IRP	Public Advisory Process	
9.H.5	The purposes of the public participation process are for the utility to provide information to, and receive and consider input from, the public regarding the development of its IRP. Topics to be discussed as part of the public participation process include, but are not limited to, the utility's load forecast; evaluation of existing supply- and demand-side resources; the assessment of need for additional resources; identification of resource options; modeling and risk assumptions and the cost and general attributes of potential additional resources; and development of the most cost-effective portfolio of resources for the utility's IRP	Public Advisory Process	
9.H.6	In its initial IRP advisory process, the utility and participants shall explore a procedure to coordinate the IRP process with renewable energy procurement plans and energy efficiency and load management program proposals. Any proposed procedure shall be designed to conserve commission, participant and utility resources and shall indicate what, if any, variances may be needed to effectuate the proposed procedure	Public Advisory Process	

Rule Section	Reporting Requirement Checklist	Subject Section	Location
9.I.1	The utility's action plan shall detail the specific actions the utility will take to implement the integrated resource plan spanning a four-year period following the filing of the utility's IRP. The action plan will include a status report of the specific actions contained in the previous action plan.	Executive Summary	Four Year Action Plan
9.I.2	An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations	Executive Summary	Four Year Action Plan

APPENDIX H. 20-YEAR REVENUE REQUIREMENT MODEL – EXISTING, OWNED GENERATION

Table 14. Strategist Inputs – O&M for Existing Plants I

Planning Period	Year	SJGS Unit 2	SJGS Unit 3	SJGS Unit 1 (2053 Retire)	SJSG Unit 4 (2053 Retire)	SJSG Unit 1 (2022 Retire)	SJSG Unit 4 (2022 Retire)	FCPP Unit 4 (2041 Retire)	FCPP Unit 5 (2041 Retire)	FCPP Unit 4 (2031 Retire)	FCPP Unit 5 (2031 Retire)
Year 1	2017	$7,785,308	10,672,061	$13,606,349	$16,808,488	$14,165,814	$16,249,022	$10,781,050	$10,781,050	$10,781,050	$10,781,050
Year 2	2018			$24,460,801	$41,658,119	$20,031,141	$38,530,489	$14,002,242	$14,002,242	$14,002,242	$14,002,242
Year 3	2019			$18,079,475	$32,428,124	$20,167,339	$38,792,471	$12,424,791	$12,424,791	$12,424,791	$12,424,791
Year 4	2020			$25,188,211	$33,085,795	$17,697,537	$34,041,733	$11,563,599	$11,563,599	$11,563,599	$11,563,599
Year 5	2021			$16,286,213	$42,812,106	$16,591,351	$31,913,951	$12,312,933	$12,312,933	$12,312,933	$12,312,933
Year 6	2022			$20,044,303	$36,920,352	$18,902,780	$36,360,060	$13,436,774	$13,436,774	$13,436,774	$13,436,774
Year 7	2023			$20,364,217	$37,483,432			$13,653,833	$13,653,833	$13,653,833	$13,653,833
Year 8	2024			$20,686,208	$38,049,723			$13,877,460	$13,877,460	$13,877,460	$13,877,460
Year 9	2025			$21,013,086	$38,624,619			$14,092,081	$14,092,081	$14,092,081	$14,092,081
Year 10	2026			$21,348,764	$39,215,633			$14,310,246	$14,310,246	$14,310,246	$14,310,246
Year 11	2027			$21,692,260	$39,820,867			$14,532,022	$14,532,022	$14,532,022	$14,532,022
Year 12	2028			$22,041,777	$40,436,848			$14,757,483	$14,757,483	$14,757,483	$14,757,483
Year 13	2029			$24,683,966	$41,063,319			$14,986,700	$14,986,700	$14,986,700	$14,986,700
Year 14	2030			$22,759,079	$46,274,964			$15,219,749	$15,219,749	$15,219,749	$15,219,749
Year 15	2031			$23,127,487	$42,351,152			$15,456,707	$15,456,707	$15,456,707	$15,456,707
Year 16	2032			$23,502,762	$43,013,223			$15,697,654	$15,697,654		
Year 17	2033			$23,884,955	$43,687,705			$15,942,671	$15,942,671		
Year 18	2034			$24,274,239	$44,374,918			$16,191,841	$16,191,841		
Year 19	2035			$24,670,767	$45,075,140			$16,445,252	$16,445,252		
Year 20	2036			$25,074,717	$45,788,700			$16,702,992	$16,702,992		

Table 15. Strategist Inputs – O&M for Existing Plants II

Planning Period	Year	Palo Verde 1 134 MW/30 MW	Palo Verde 2 130 MW/124 MW	Palo Verde 1 104 MW	Palo Verde 2 10 MW	Palo Verde 3 134 MW	Afton	Luna	Lordsburg	La Luz	Reeves	Rio Bravo
		Palo Verde Leases Expire		PV1 & PV2 Leases Convert								
Year 1	2017	$41,936,976	$28,005,121	$-	$-		$11,462,267	$6,153,213	$3,086,360	$1,931,042	$4,196,411	$987,163
Year 2	2018	$43,024,085	$28,626,593	$-	$-	$26,911,814	$9,408,256	$8,145,651	$3,105,688	$2,003,667	$4,360,321	$1,050,227
Year 3	2019	$46,715,935	$25,318,150	$-	$-	$27,077,345	$9,495,138	$6,603,159	$3,130,857	$2,031,540	$4,399,812	$6,080,818
Year 4	2020	$46,999,387	$28,830,846	$-	$-	$23,315,631	$9,632,738	$6,674,534	$3,153,819	$2,060,193	$4,501,757	$1,112,321
Year 5	2021	$43,224,400	$28,843,974	$-	$-	$27,108,614	$14,141,941	$8,226,511	$3,177,270	$2,089,513	$4,730,742	$1,144,615
Year 6	2022	$46,051,343	$28,076,680	$-	$-	$26,103,814	$10,954,429	$6,863,818	$3,139,599	$2,016,078	$4,773,392	$1,984,716
Year 7	2023	$6,775,363	$28,432,394	$23,013,663	$-	$26,459,627	$11,077,140	$6,922,049	$3,157,419	$2,030,676	$4,848,450	$2,014,486
Year 8	2024	$6,854,114	$24,845,124	$23,289,027	$2,310,562	$26,821,940	$11,203,436	$6,981,254	$3,175,509	$2,045,493	$4,924,927	$2,044,704
Year 9	2025	$6,932,956	$25,179,825	$23,564,709	$2,338,139	$27,184,803	$11,333,519	$7,041,454	$3,193,796	$2,060,533	$5,002,871	$2,075,374
Year 10	2026	$7,012,980	$25,519,546	$23,844,525	$2,366,129	$27,553,109	$11,467,606	$7,102,669	$3,212,432	$2,075,798	$5,082,329	$2,106,505
Year 11	2027	$7,094,205	$25,864,363	$24,128,539	$2,394,538	$27,926,939	$11,605,930	$7,164,923	$3,231,351	$2,091,292	$5,163,355	$2,138,102
Year 12	2028	$7,176,648	$26,214,352	$24,416,813	$2,423,374	$28,306,377	$11,748,744	$7,228,237	$3,250,557	$2,107,019	$5,246,003	$2,170,174
Year 13	2029	$7,260,328	$26,569,591	$24,709,411	$2,452,643	$28,691,506	$11,896,319	$7,292,637	$3,270,055	$2,122,981	$5,330,333	$2,202,727

Planning Period	Year	Palo Verde 1 134 MW/30 MW	Palo Verde 2 130 MW/124 MW	Palo Verde 1 104 MW	Palo Verde 2 10 MW	Palo Verde 3 134 MW	Afton	Luna	Lordsburg	La Luz	Reeves	Rio Bravo
Year 14	2030	$7,345,263	$26,930,158	$25,006,398	$2,482,350	$29,082,413	$12,048,949	$7,358,146	$3,289,849	$2,139,183	$5,416,407	$2,235,767
Year 15	2031	$7,431,471	$27,296,135	$25,307,839	$2,512,503	$29,479,183	$12,206,951	$7,424,791	$3,309,944	$2,155,628	$5,504,292	$2,269,304
Year 16	2032	$7,518,973	$27,667,600	$25,613,803	$2,543,109	$29,881,904	$12,361,659	$7,492,598	$3,330,345	$2,172,319	$5,594,060	$2,303,344
Year 17	2033	$7,607,788	$28,044,638	$25,924,356	$2,574,173	$30,290,666	$12,427,502	$7,561,595	$3,351,057	$2,189,261	$5,685,787	$2,337,894
Year 18	2034	$7,697,935	$28,427,332	$26,239,567	$2,605,704	$30,705,560	$12,594,222	$7,631,810	$3,372,086	$2,206,457	$5,779,554	$2,372,962
Year 19	2035	$7,789,434	$28,815,765	$26,559,506	$2,637,707	$31,126,677	$12,767,044	$7,703,274	$3,393,436	$2,223,911	$5,875,448	$2,408,557
Year 20	2036	$7,882,305	$29,210,026	$26,884,245	$2,670,191	$31,554,111	$12,946,363	$7,776,018	$3,415,112	$2,241,627	$5,818,825	$2,444,685

Table 16. Strategist Inputs – Revenue Requirement for Ongoing Capital Expenitures for Existing Plants I

Planning Period	Year	FCPP Unit 4 (2041 Retire)	FCPP Unit 5 (2041 Retire)	FCPP Unit 4 (2031 Retire)	FCPP Unit 5 (2031 Retire)
Year 1	2017	$2,501,238	$2,501,238	$2,501,238	$2,501,238
Year 2	2018	$6,848,193	$6,848,193	$6,848,193	$6,848,193
Year 3	2019	$8,819,091	$8,819,091	$8,819,091	$8,819,091
Year 4	2020	$9,272,440	$9,272,440	$9,272,440	$9,272,440
Year 5	2021	$9,526,142	$9,526,142	$9,526,142	$9,526,142
Year 6	2022	$9,968,938	$9,968,938	$9,968,938	$9,968,938
Year 7	2023	$10,562,594	$10,562,594	$10,562,594	$10,562,594
Year 8	2024	$11,155,965	$11,155,965	$11,155,965	$11,155,965
Year 9	2025	$11,749,701	$11,749,701	$11,749,701	$11,749,701
Year 10	2026	$12,343,415	$12,343,415	$12,343,415	$12,343,415
Year 11	2027	$12,937,601	$12,937,601	$12,947,017	$12,947,017
Year 12	2028	$13,534,409	$13,534,409	$13,628,810	$13,628,810
Year 13	2029	$14,136,935	$14,136,935	$13,496,087	$13,496,087
Year 14	2030	$14,749,174	$14,749,174	$12,976,174	$12,976,174
Year 15	2031	$15,376,309	$15,376,309	$12,419,733	$12,419,733
Year 16	2032	$16,022,572	$16,022,572	$-	$-
Year 17	2033	$16,695,105	$16,695,105	$-	$-
Year 18	2034	$17,408,483	$17,408,483	$-	$-
Year 19	2035	$18,184,705	$18,184,705	$-	$-
Year 20	2036	$19,058,532	$19,058,532	$-	$-

Table 17. Strategist Inputs – Revenue Requirement for Ongoing Capital Expenitures for Existing Plants II

Planning Period	Year	Palo Verde 1 134 MW/30 MW	Palo Verde 2 130 MW/124 MW	Palo Verde 1 104 MW	Palo Verde 2 10 MW	Palo Verde 3 134 MW	Afton	Luna	Lordsburg	La Luz	Reeves	Rio Bravo
		Palo Verde Leases Expire		PV1 & PV2 Leases Convert								
Year 1	2017	$187,081	$672,344	$654,154	$56,481	$-	$620,321	$83,302	$9,050	$53,126	$78,613	$49,118
Year 2	2018	$412,989	$2,064,850	$1,444,076	$173,461	$1,274,094	$979,723	$693,243	$26,917	$85,886	$116,237	$73,853
Year 3	2019	$633,592	$3,117,072	$2,215,444	$261,854	$2,662,046	$1,042,585	$1,021,697	$43,104	$83,090	$252,433	$71,020
Year 4	2020	$932,485	$4,246,670	$3,260,567	$356,748	$3,551,576	$1,099,340	$1,050,532	$57,697	$80,432	$511,329	$68,288
Year 5	2021	$1,121,193	$5,320,739	$3,920,414	$446,976	$4,239,711	$1,128,992	$1,763,617	$72,567	$77,897	$593,339	$65,649
Year 6	2022	$1,301,855	$6,346,889	$4,552,123	$533,180	$5,125,051	$1,308,955	$2,416,475	$88,157	$88,275	$663,232	$75,340
Year 7	2023	$1,529,110	$7,449,954	$5,346,752	$625,844	$6,013,309	$1,575,215	$2,819,640	$104,159	$106,987	$781,017	$91,505

Planning Period	Year	Palo Verde 1 134 MW/30 MW	Palo Verde 2 130 MW/124 MW	Palo Verde 1 104 MW	Palo Verde 2 10 MW	Palo Verde 3 134 MW	Afton	Luna	Lordsburg	La Luz	Reeves	Rio Bravo
Year 8	2024	$1,753,152	$8,537,117		$717,173	$6,888,503	$1,839,151	$3,220,324	$120,067	$125,282	$898,666	$107,423
Year 9	2025	$1,974,233	$9,609,319			$7,751,230	$2,101,080	$3,619,300	$135,895	$143,181	$1,016,588	$123,135
Year 10	2026	$2,192,523	$10,667,416			$8,601,800	$2,361,338	$4,017,203	$151,661	$160,733	$1,135,301	$138,703
Year 11	2027	$2,408,158	$11,712,069			$9,440,806	$2,620,522	$4,414,780	$167,392	$177,977	$1,255,448	$154,197
Year 12	2028	$2,621,395	$12,744,045			$10,268,907	$2,879,359	$4,813,179	$183,118	$194,943	$1,377,808	$169,689
Year 13	2029	$2,832,542	$13,764,371			$11,086,659	$3,138,738	$5,213,438	$198,882	$211,639	$1,503,560	$185,252
Year 14	2030	$3,041,937	$14,774,290			$11,894,815	$3,399,678	$5,616,749	$214,741	$228,065	$1,634,509	$200,976
Year 15	2031	$3,250,036	$15,775,489			$12,694,401	$3,660,827	$6,020,908	$230,613	$244,122	$1,771,519	$216,808
Year 16	2032	$3,458,144	$16,772,766			$13,488,558	$3,929,183	$6,437,195	$246,932	$260,241	$1,922,640	$233,474
Year 17	2033	$3,668,315	$17,776,134			$14,283,353	$4,204,250	$6,864,897	$263,671	$276,545	$2,093,082	$251,212
Year 18	2034	$3,882,291	$18,794,155			$15,087,449	$4,489,272	$7,309,307	$281,036	$292,813	$2,296,099	$270,256
Year 19	2035	$4,102,630	$19,834,051			$15,907,614	$4,788,983	$7,778,126	$299,322	$308,827	$2,559,553	$291,078
Year 20	2036	$4,332,174	$20,906,825			$16,746,685	$5,110,537	$8,282,969	$290,793	$324,600	$2,432,549	$280,183

Table 18. Strategist Inputs – Revenue Requirement for Palo Verde Generation Station Leases

Planning Year	Year	Capital cost + ongoing capital expenditures		Lease expiration	
		PV1 (104 MW)	PV1 (10 MW)	PV1 (104 MW)	PV1 (10 MW)
Year 1	2017	$-	$-	$-	$-
Year 2	2018	$-	$-	$-	$-
Year 3	2019	$-	$-	$-	$-
Year 4	2020	$-	$-	$-	$-
Year 5	2021	$-	$-	$-	$-
Year 6	2022	$-	$-	$-	$-
Year 7	2023	$25,956,792	$-	$10,228,119	$-
Year 8	2024	$25,685,308	$2,632,639	$10,243,971	$891,535
Year 9	2025	$25,645,201	$2,620,222	$9,982,586	$898,562
Year 10	2026	$25,733,496	$2,636,232	$9,677,419	$875,306
Year 11	2027	$25,894,298	$2,668,940	$9,372,253	$848,548
Year 12	2028	$26,084,697	$2,705,439	$9,067,086	$821,790
Year 13	2029	$26,294,823	$2,744,476	$8,761,919	$795,032
Year 14	2030	$26,507,564	$2,785,129	$8,456,752	$768,274
Year 15	2031	$26,715,517	$2,825,719	$8,151,586	$741,516
Year 16	2032	$26,921,139	$2,865,527	$7,846,419	$714,758
Year 17	2033	$27,127,267	$2,904,815	$7,541,252	$688,000
Year 18	2034	$27,337,777	$2,943,899	$7,236,085	$661,242
Year 19	2035	$27,558,019	$2,983,218	$6,930,919	$634,484
Year 20	2036	$27,795,491	$3,023,378	$6,625,752	$607,726
Year 21	2037	$28,060,911	$3,065,240	$6,320,585	$580,968

Planning Year	Year	Capital cost + ongoing capital expenditures		Lease expiration	
		PV1 (104 MW)	PV1 (10 MW)	PV1 (104 MW)	PV1 (10 MW)
Year 22	2038	$28,453,038	$3,110,040	$6,015,418	$554,210
Year 23	2039	$29,082,116	$3,167,893	$5,710,252	$527,452
Year 24	2040	$29,909,777	$3,250,300	$5,405,085	$500,694
Year 25	2041	$30,921,986	$3,354,266	$5,099,918	$473,936
Year 26	2042	$32,237,965	$3,479,610	$4,794,751	$447,178
Year 27	2043	$34,106,113	$3,640,401	$(0)	$420,420
Year 28	2044	$37,176,448	$3,866,115	$(0)	$-
Year 29	2045	$44,164,615	$4,234,116	$(0)	$-
Year 30	2046	$-	$5,068,448	$-	$-
NPV (2017$)		**$267,010,142**	**$28,167,196**	**$76,929,438**	**$6,641,567**
		$295,177,338		**$83,571,005**	

Table 19. Strategist Inputs – Revenue Requirement and O&M for SJGS Continues and Retires

Planning Period	Year	SI Revenue Requirements			SJGS Coal Reclamation Costs	
		SJGS Continue	SJGS Retire	Retire minus Continue	SJGS Retire	SJGS Retire + Reclamation
Year 1	2017	$51,241,347	$51,241,347	$0	$0	$51,241,347
Year 2	2018	$56,353,944	$56,541,852	$187,908	$0	$56,541,852
Year 3	2019	$56,209,525	$56,932,239	$722,714	$0	$56,932,239
Year 4	2020	$56,563,833	$55,894,264	$(669,569)	$0	$55,894,264
Year 5	2021	$57,649,659	$53,969,212	$(3,680,447)	$0	$53,969,212
Year 6	2022	$56,537,844	$36,670,281	$(19,867,563)	$0	$36,670,281
Year 7	2023	$55,092,170	$38,093,353	$(16,998,817)	$2,423,414	$40,516,767
Year 8	2024	$55,340,814	$37,149,618	$(18,191,196)	$2,060,826	$39,210,444
Year 9	2025	$55,584,071	$36,138,861	$(19,445,209)	$1,815,752	$37,954,613
Year 10	2026	$55,822,912	$35,025,019	$(20,797,893)	$1,386,014	$36,411,033
Year 11	2027	$56,094,803	$33,892,601	$(22,202,202)	$597,734	$34,490,335
Year 12	2028	$56,427,501	$32,759,063	$(23,668,438)	$481,556	$33,240,619
Year 13	2029	$57,316,023	$31,624,338	$(25,691,684)	$472,781	$32,097,119
Year 14	2030	$58,627,255	$30,488,355	$(28,138,900)	$477,608	$30,965,963
Year 15	2031	$59,352,237	$29,351,035	$(30,001,201)	$482,243	$29,833,279
Year 16	2032	$59,681,237	$28,212,299	$(31,468,938)	$489,404	$28,701,703

Planning Period	Year	SI Revenue Requirements			SJGS Coal Reclamation Costs	
		SJGS Continue	SJGS Retire	Retire minus Continue	SJGS Retire	SJGS Retire + Reclamation
Year 17	2033	$59,983,757	$27,072,058	$(32,911,699)	$497,620	$27,569,678
Year 18	2034	$60,395,445	$25,930,223	$(34,465,222)	$512,444	$26,442,667
Year 19	2035	$60,921,611	$24,786,693	$(36,134,918)	$528,664	$25,315,358
Year 20	2036	$61,460,135	$23,641,367	$(37,818,767)	$547,632	$24,189,000
Year 21	2037	$62,000,403	$22,494,134	$(39,506,269)	$567,516	$23,061,650
Year 22	2038	$63,291,017	$21,344,876	$(41,946,142)	$562,105	$21,906,980
Year 23	2039	$65,118,305	$20,193,469	$(44,924,836)	$595,164	$20,788,633
Year 24	2040	$66,094,899	$19,039,780	$(47,055,119)	$630,908	$19,670,688
Year 25	2041	$66,667,310	$17,883,669	$(48,783,641)	$668,859	$18,552,528
Year 26	2042	$67,275,234	$16,724,987	$(50,550,248)	$709,157	$17,434,143
Year 27	2043	$67,958,591	$(816,498)	$(68,775,090)	$751,950	$(64,548)
Year 28	2044	$68,734,307	$(867,424)	$(69,601,731)	$797,398	$(70,026)
Year 29	2045	$69,632,358	$(921,430)	$(70,553,787)	$845,670	$(75,760)
Year 30	2046	$70,695,933	$(978,708)	$(71,674,641)	$896,944	$(81,763)
Year 31	2047	$64,710,020	$(1,039,461)	$(65,749,481)	$951,415	$(88,047)
Year 32	2048	$69,618,140	$(1,103,908)	$(70,722,048)	$1,009,285	$(94,623)
Year 33	2049	$73,202,968	$(1,172,277)	$(74,375,245)	$1,070,774	$(101,503)
Year 34	2050	$77,695,728	$(1,244,815)	$(78,940,543)	$1,136,113	$(108,702)
Year 35	2051	$75,565,893	$(1,321,783)	$(76,887,677)	$1,205,552	$(116,232)
Year 36	2052	$72,244,068	$(1,403,460)	$(73,647,527)	$1,279,354	$(124,106)
Year 37	2053	$62,744,322	$(703,071)	$(63,447,393)	$1,357,802	$654,730
NPV		**$709,212,059**	**$437,674,613**	**$(271,537,446)**	**$10,706,683**	**$445,172,088**

Table 20. Strategist Inputs – Global Model Assumptions

Input	Value	Notes
Discount Rate	7.71%	
Planning time period	20	
Planning Period Years	2017-2036	
Global Escalation	1.5%	
Plant Life	varies	See Appendix J and Appendix K
Annual Reserve Margin Target	14%	
Federal Tax Incentives	30%	Throughout the planning period

Input	Value	Notes
Capacity factor for Existing Private Solar	26%, 27%, 32%	Fixed-Tilt, Thin-Film Tracking and Poly Tracking
Capacity factor for Existing Wind	29%, 23%	NMWEC and Red Mesa respectively
Capacity factor for new Solar PV resources	32%	
Capacity factor for new wind resources	45%	
Solar PV Technologies - fixed tilt (existing)	55%	
Solar PV Technologies - single axis tracking (existing)	76%	
Effective Load Carrying Capability – New Solar PV	35%	See solar sensitivity analysis for details
Effective Load Carrying Capability – New Wind	5%	
Emergency Energy Cost	$300/MWh	
Spinning Reserve Requirements	6%	

Table 21. 2017 IRP Key Assumptions

Scenario	Value
San Juan Closure 2022	
San Juan units 1 & 4 closure date	9/30/2022
San Juan units 2 & 3 closure date	12/31/2017
Revenue Requirements excludes non-jurisdictional costs associated with 65 MW of unit 4 per BART Stipulation (Case No. 13-00390-UT)	
Recovery of 100% of undepreciated assets over a 20-year period	
Undepreciated assets excludes costs associated with 132 MW per BART Stipulation (Case No. 13-00390-UT)	
Includes costs associated with surface and underground coal mine reclamation and plant decommissioning	
San Juan Closure 2053	
San Juan units 1 & 4 closure date	12/31/2053
San Juan units 2 & 3 closure date	12/31/2017
Revenue Requirements excludes non-jurisdictional costs associated with 65 MW of unit 4 per BART Stipulation (Case No. 13-00390-UT)	
Includes costs associated with surface and underground coal mine reclamation and plant decommissioning	
Four Corners	
Scenarios assume exit date	12/31/2031 & 12/31/2041
Recovery of 100% of undepreciated assets over a 10-year period	

Includes costs associated with coal mine reclamation and plant decommissioning	
Palo Verde	
Palo Verde leased capacity revenue requirement includes lease expense through the end of the lease agreement plus all retained obligations	
Retained obligations include: Undepreciated asset recovery of leasehold improvements (return on and of) and Plant decommissioning (NDT Funding)	
Retained obligations start in 2023 (104 MW Unit 1) and 2024 (10 MW Unit 2)	
Lease retention revenue requirement includes purchase of leased capacity, ongoing capital, and operating expenses starting the first year after the lease agreements expires	
Undepreciated assets includes NBV of leasehold improvements	
Recovery of 100% of undepreciated assets over a 20-year period	
Revenue requirement includes transmission wheeling costs	
Palo Verde units 1 & 2 costs are allocated between owned capacity and leased capacity on a per MW prorated share	
All Owned Generation Resource Assumptions	
Ongoing capital and outage O&M are based on an average of the most recently available budgeted data for 2017 thru 2021 and normalized	
Bonus Tax Depreciation ADIT through 2019	2017 = 50% 2018 = 40% 2019 = 30%
Ongoing O&M is based on the most recently available budgeted data for 2017 through 2021 and escalated 1.5% starting in 2022	
Average Rate Base	
Ongoing capital is depreciated at a rate to be fully depreciated by the end of the assets projected useful life	
Property Tax rates are based on NMPRC Case No. 16-00276-UT	
Assume recovery of balanced draft technology, Palo Verde unit 2 leasehold improvements for the purchased 64MW, and Palo Verde NDT Contributions	
Operating Expenses include O&M, Fuel handling, gas transportation, Coal mine reclamation (underground and surface), depreciation, plant decommissioning, amortization of undepreciated assets (if applicable), property tax, payroll tax and income tax	
Operating Expenses exclude fuel, DOE spent fuel refund amortization, and corporate allocated A&G	
Rate base includes net plant, accumulated deferred income taxes, undepreciated assets (if applicable), inventory, fuel stock, prepaids and ARO liability	
WACC	
Approved WACC from NMPRC case no. 15-00261-UT final order	
Weighted average cost of debt	2.94%
Weighted average cost of preferred stock	0.02%

Weighted average cost of common stock	4.75%
After Tax WACC	7.71%
Pre-Tax WACC	10.71%
Combined Statutory Tax Rate	38.62%
* Definitions: NDT - Nuclear Decommissioning Trust ARO - Asset Retirement Obligation WACC - Weighted Average Cost of Capital	

APPENDIX I. DETAILS OF CO_2 AND GAS PRICE FORECASTS

This information was presented at PNM's September 22, 2017 IRP meeting.

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Forecasts and Assumptions for IRP

Prepared for PNM

September 2016

Answers for infrastructure and cities.

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Agenda

- Introduction
- Tools and Methodology
  - AuroraXMP – electric market dispatch analysis
  - GPCM – natural gas pipeline flow analysis
- Baseline Scenario Assumptions and Forecasts
- Alternate Scenario Assumptions and Forecasts
  - Approach
  - High
  - Low
- Questions and Discussion

Introduction

- Pace Global developed market assumptions for PNM’s 2017 IRP process.
- The key inputs are natural gas prices, carbon prices and power prices.
- Pace Global used its comprehensive power market modeling tools to generate these forecasts under a Baseline and High and Low scenarios to reflect uncertainty of market conditions over the long-term planning horizon.

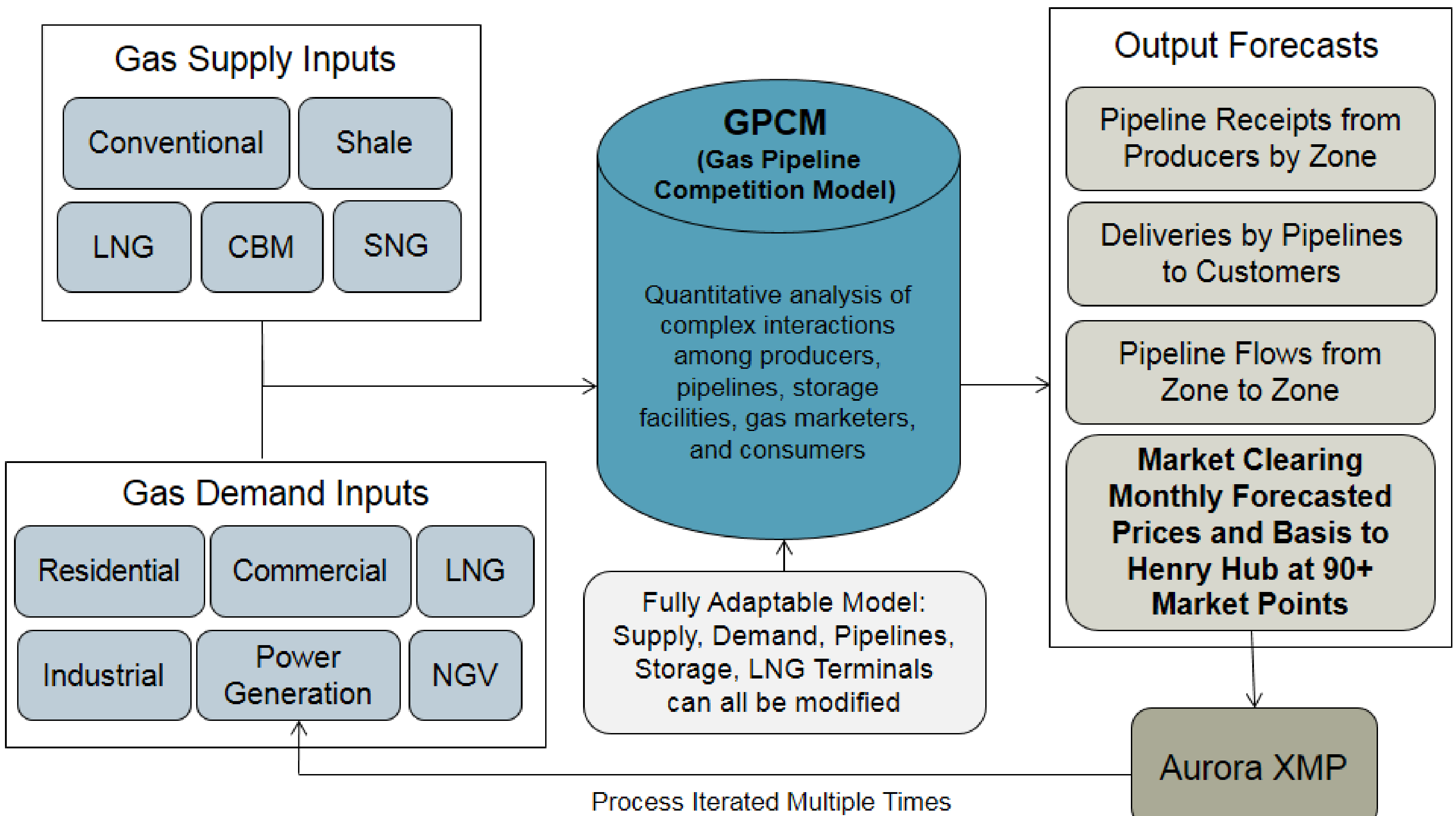
Scenario	High Level Description
Baseline	Reference view based on market forwards and longer term by fundamentals accounting for expected policy
High	High expected power pricing based on high natural gas and carbon pricing throughput the forecast period
Low	Low expected power pricing based on low natural gas and carbon pricing throughout the forecast period

- This presentation summarizes the methodology used, assumptions and forecasts for the IRP process.

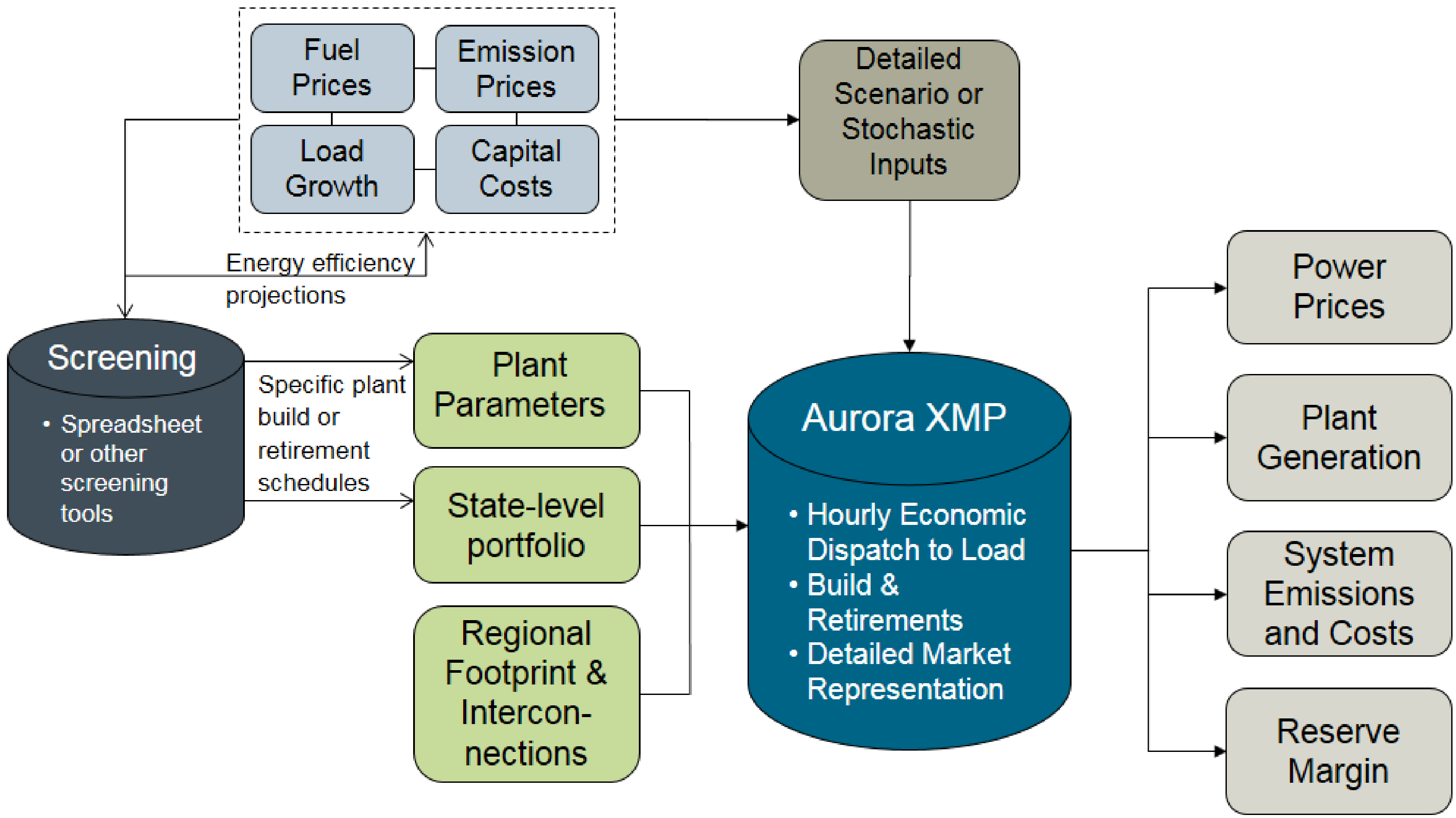
Tools and Methodology

Answers for infrastructure and cities.

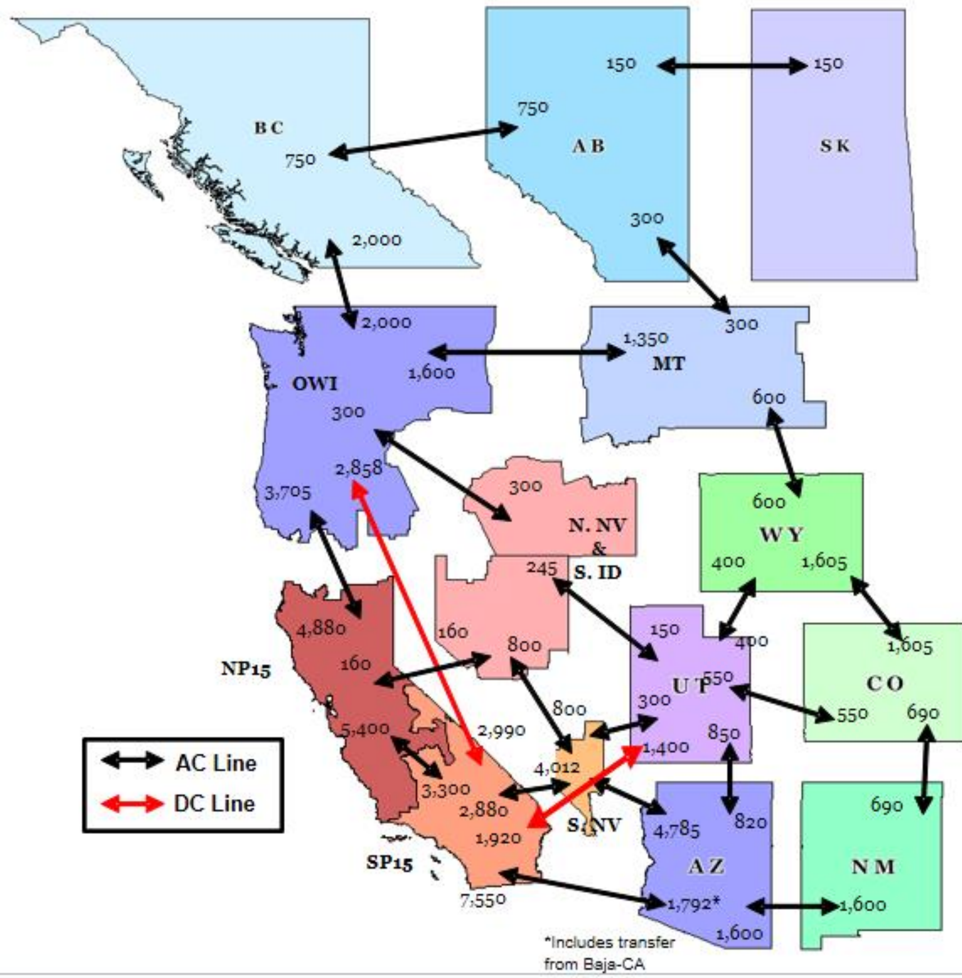
Natural Gas Prices Generated Using GPCM Integrated with Aurora XMP to Provide A Balanced and Iterative View of Gas Burn and Prices



Pace Global Zonal Market Analysis, Aurora XMP
Comprehensive Tool for Analyzing Power Markets



Analysis Was Performed with Full WECC Footprint
AuroraXMP Regional and National Analysis



Approach to Pricing Carbon Under the Clean Power Plan Starts with the Shadow Price for Carbon

The shadow price represents the marginal cost of carbon reduction for a given set of conditions – in this case limits under the Clean Power Plan (CPP).

- Accounts for operational parameters but does *not* directly account for capital costs and other longer-term costs that may be needed to comply with carbon limits
- Measured in terms of \$/short ton CO2 – can be converted to \$/MWh to represent ERC prices in rate regime
- Pace Global relies on AURORAxmp's capabilities to solve for carbon shadow pricing within dispatch simulations

• Pace Global solves for the shadow price of carbon based on national dispatch analysis to determine Baseline carbon price.

Baseline Scenario

Answers for infrastructure and cities.

Overview Baseline Assumptions

The Baseline Scenario

- Key assumptions driving the Baseline scenario are:
  - In the short-term (2016-2018), the Baseline assumes a business-as-usual perspective for all market drivers, consistent with market forwards.
  - By 2018, it is assumed that most states, including New Mexico will opt for a mass-based CPP compliance path, effective in 2022:
    - Easier to administer than rate-based
    - Retirements aid NM compliance
    - States will join to create liquid trading market
  - Gas prices increase somewhat from current low levels beginning around 2018 as demand catches up to shale supply.
  - Power prices move up with gas and as CPP compliance begins in 2022.
  - Long term, gas and power prices tend to level out in real terms.

	Baseline		
Time Frame:	**ST**	**MT**	**LT**
Load Growth	B	↗	↗
Gas Prices	B	↗	→
Coal Prices	B	↗	↗
CO2 Prices	B	↗	↗
Power Prices	B	↗	↗
Capital Cost - Gas	B	→	↘
Capital Cost - RE	B	↘	↘
Retirements	B	↗	↗
Additions	B	↗	↗
Economy	B	↗	↗

ST=2016-18, MT=2019-25, LT=2026-36

Natural Gas Supply Outlook by Source

Near Term – 2016

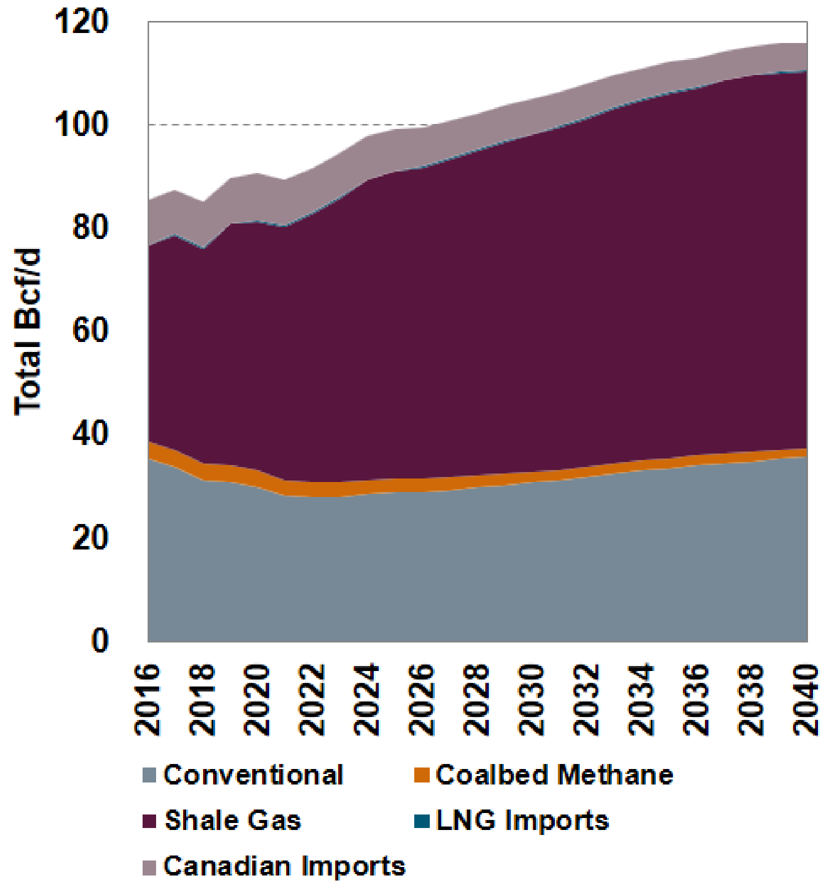
Production growth finally slows in 2016 as continued low gas prices begin to take a toll on gas producers.

Midterm – 2017-2020

L48 production growth will face some difficulty as low gas prices persist and producers face bankruptcy, but anticipated demand will help to buoy an increase in supply.

Long Term – 2021-2040

Production growth resumes robust growth in the long-term, with the majority of growth coming from shale.



Source: Pace Global

Natural Gas Demand Outlook by End Use Sector

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Near Term – 2016

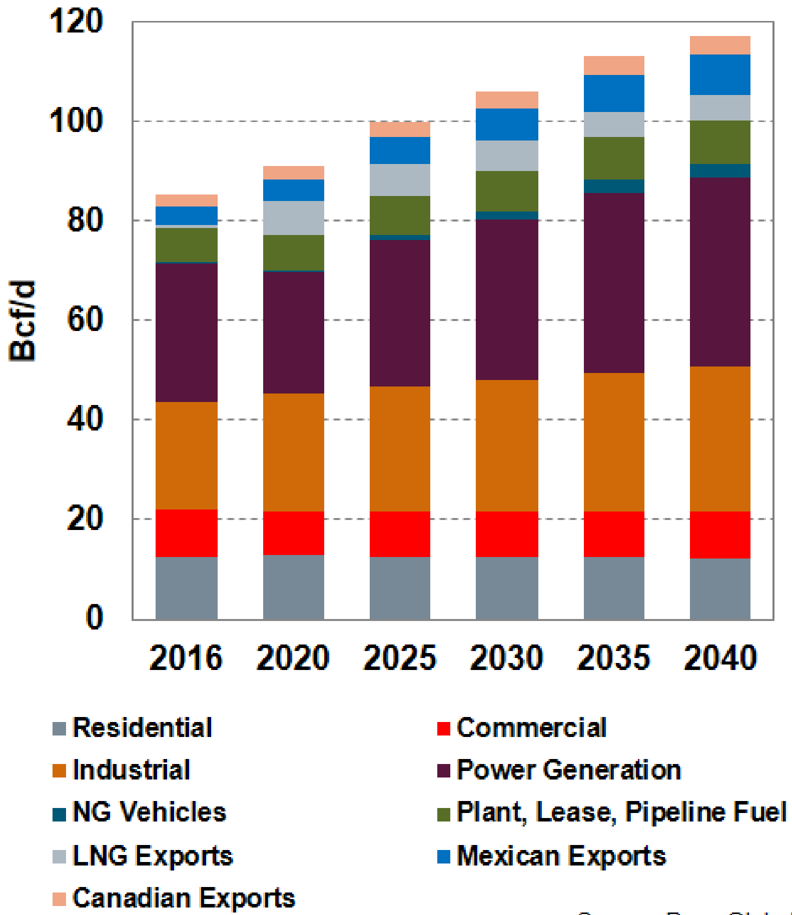
Power burn YTD in 2016 has averaged 24.2 Bcf/d, on a similar path to 2012 when gas prices were low. Summer burn is expected to push this average upward.

Midterm – 2017-2020

A ramp-up in demand from LNG exports, Mexican exports, and industrial demand will add 8.7 Bcf/d by 2020 over 2016.

Long Term – 2021-2040

Demand will continue to grow, with the power sector continuing to take market share from coal-fired generation and as a complement to intermittent renewables.



Source: Pace Global

Power Sector Natural Gas Generation Outlook

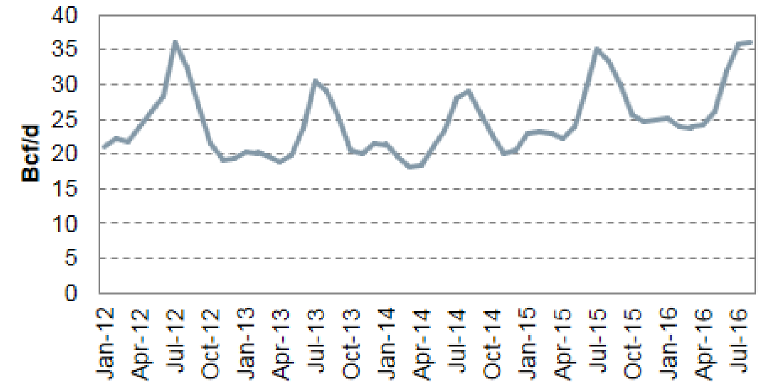
Power Sector Gas Burn Since 2012

Continued low gas prices are supporting higher gas burn levels, both in the summer trough months and in the peak winter months. Power sector gas consumption is likely to be strong in 2016-17 with a continuation of low gas prices.

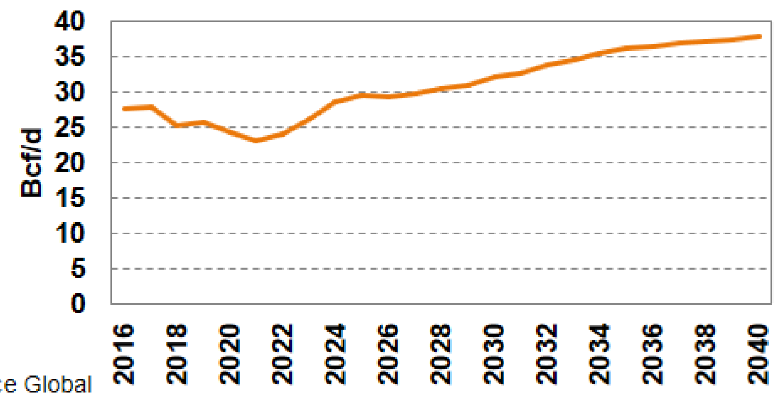
Outlook for Power Sector Gas Burn

While the CPP was issued in Aug. 2015, a recent SCOTUS stay has put many states' plans on hold. Expected gas burn will see a ramping up as the plan enters into the compliance period post-2022.

Monthly U.S. Gas Burn Since 2012

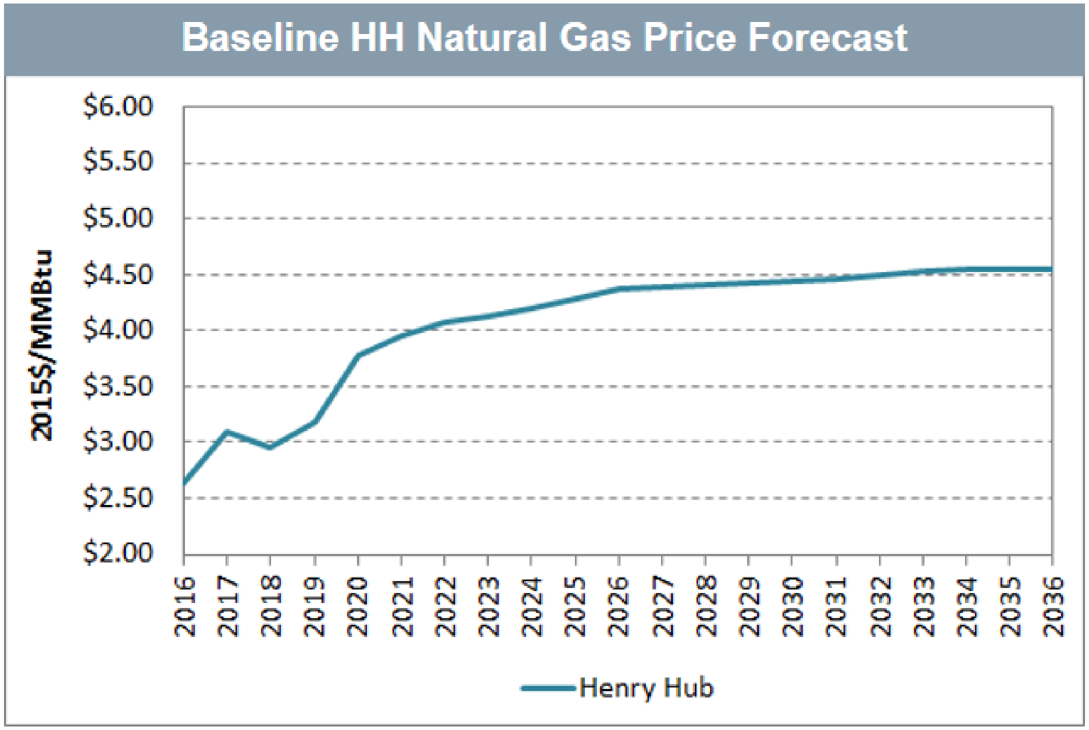


Forecasted Annual U.S. Gas Burn



Source: Pace Global

Baseline Natural Gas Prices – Henry Hub

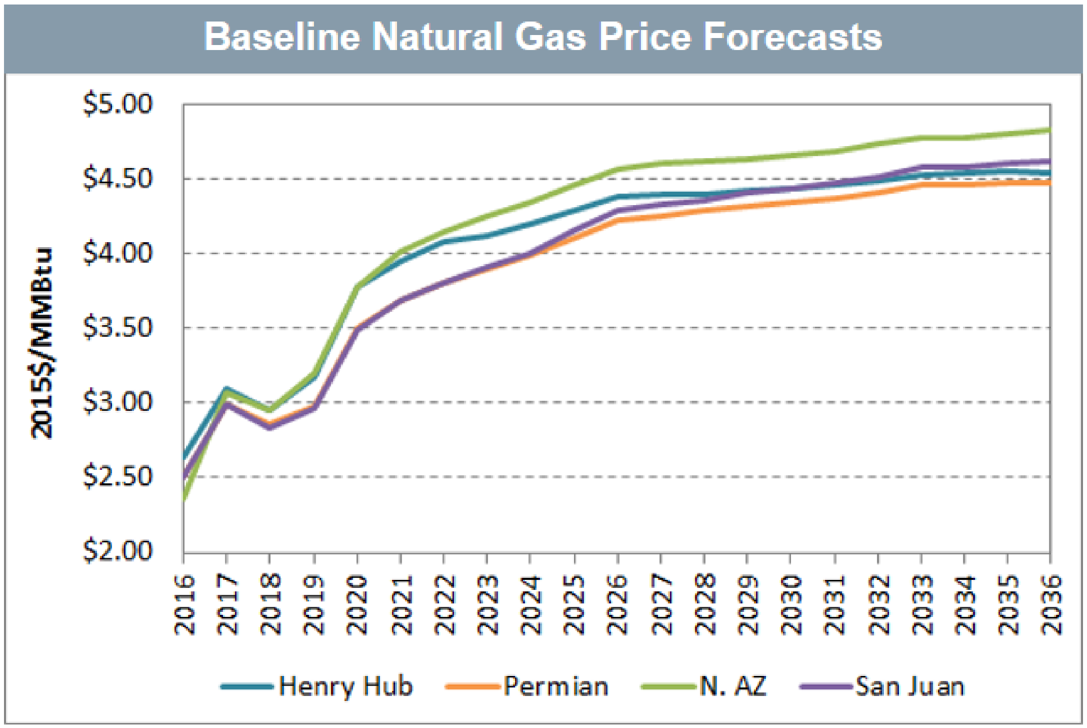


Henry Hub

- **Near Term -** forwards indicate average price near between $2.50-$3/MMBtu, shale gas oversupply
- **Mid-Term -** Gulf Coast prices expected to rise as a new demand (LNG and Mexican exports, industrial use) turn the region into a premium market
- **Long-Term** - Ample shale supplies will constrain prices to between $4.00-5.00, gradually increasing over time.

Note: Forecast based on NYMEX forwards as of July 2016

Baseline Natural Gas Prices – Henry Hub and Key Southwest Hubs



Note: Forecast based on NYMEX forwards as of July 2016

Permian

- Longstanding production region in southwest NM / western TX. Permian gas is less competitive than new shale gas sources (Eagle Ford, Utica, Marcellus) that are meeting new Gulf Coast demand (LNG, etc.) driving negative basis for the forecast period.

San Juan

- Longstanding conventional production region in northwest NM into southern CO. Production of gas fallen significantly w/ shale economics, expect narrowing basis turning positive with higher prices and increasing demand.

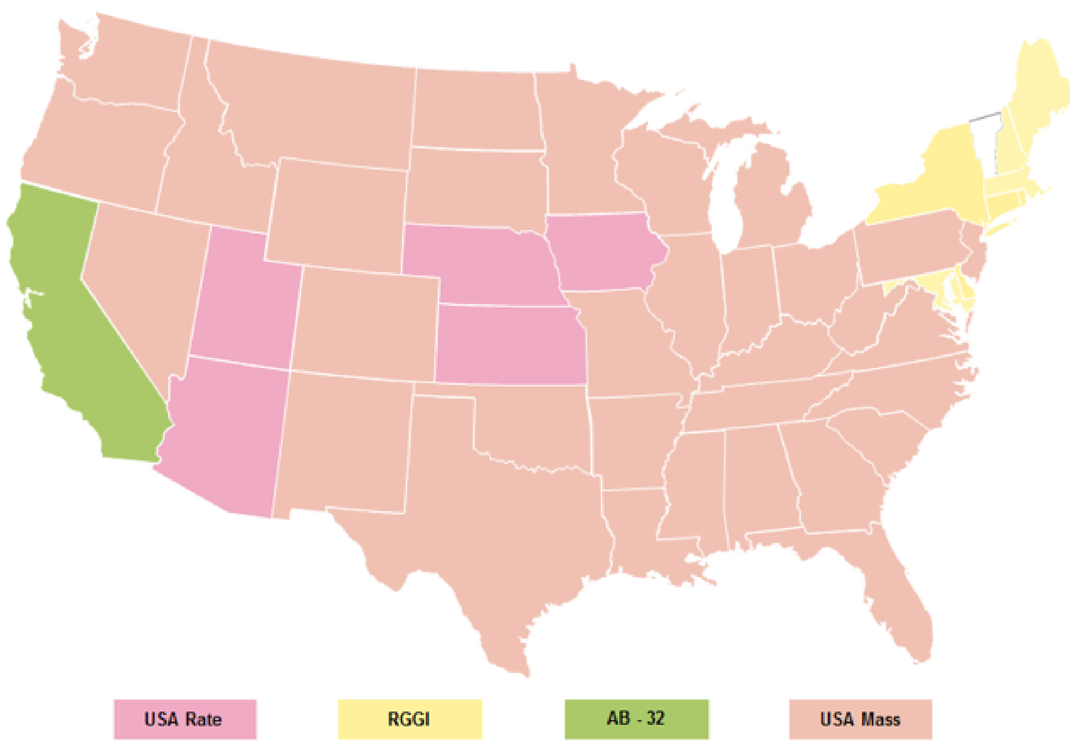
Northern Arizona

- Price point in N. AZ. Commands positive basis over HH due to strong demand in Arizona, Southern California and Mexico; regional is less impacted by eastern shale supply displacement.

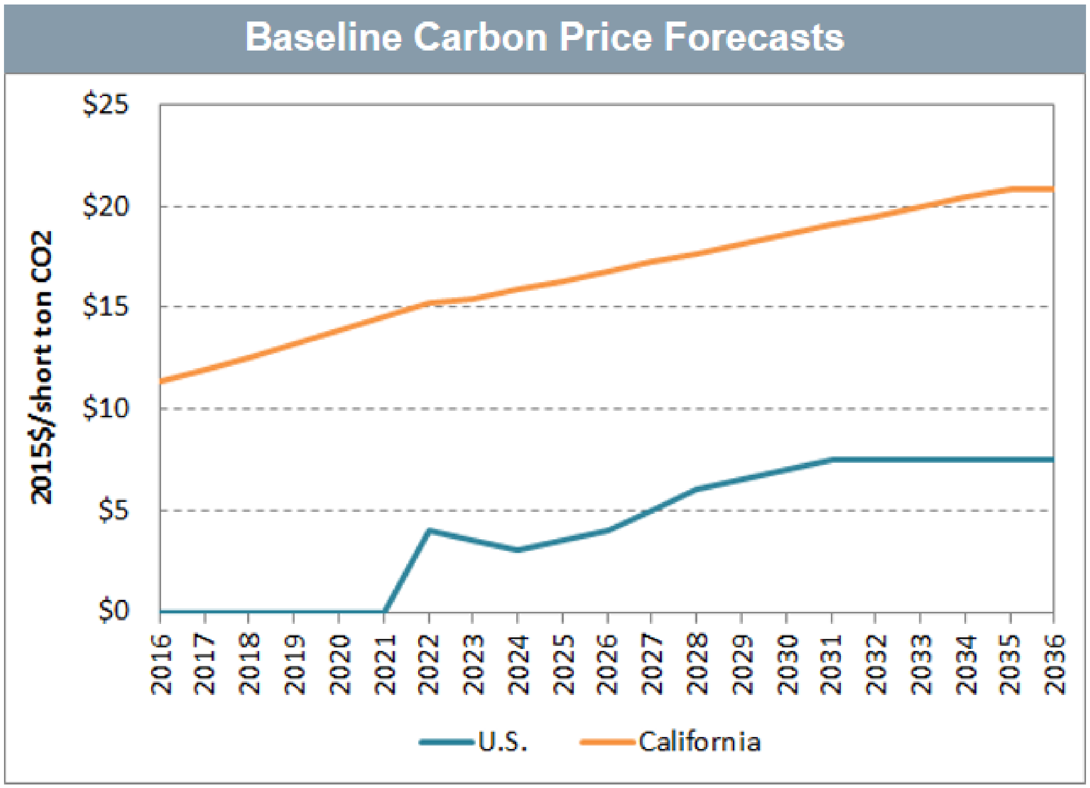
Carbon Prices Based on Assumptions Regarding State Approaches to Comply with the CPP

- Noting uncertainties of the CPP, Pace Global defined states' expected approach to comply with the CPP in the Baseline scenario.
- California and RGGI states maintain trading under existing programs – California maintains caps lower than CPP goal to meet more aggressive state reductions.
- States with strong propensity to meeting a rate goal take this approach – others take mass goal w/ interstate trading.

Reference View of State Rate-Mass Designation



Baseline Carbon Prices – U.S. and California



U.S.

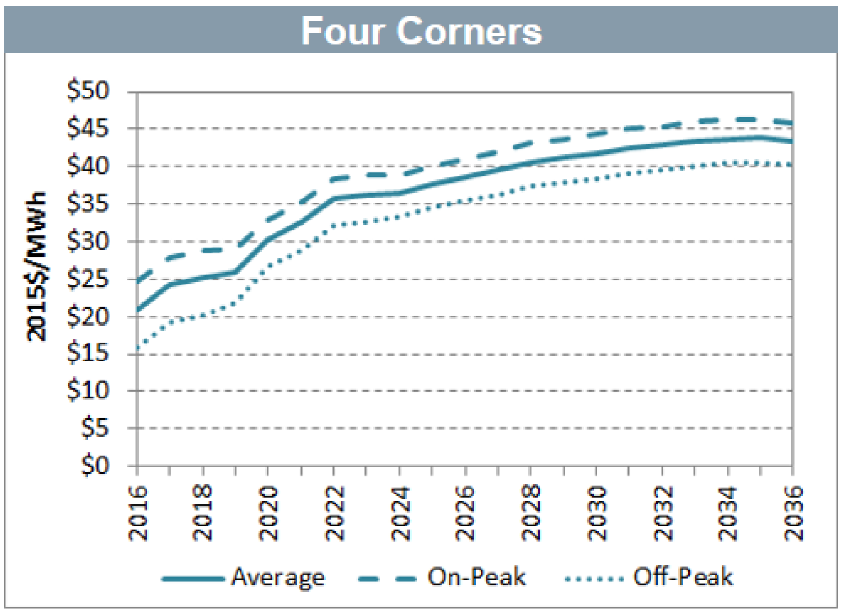
- **Near Term –** no national price on carbon before 2022
- **Mid-Term –** CPP as finalized becomes effective in 2022 with liquid opt-in national trading, market trades at a premium in early years as the market finds equilibrium
- **Long-Term** – Moderate gas prices and planned coal retirements help to mitigate the carbon price under the $10/ton level

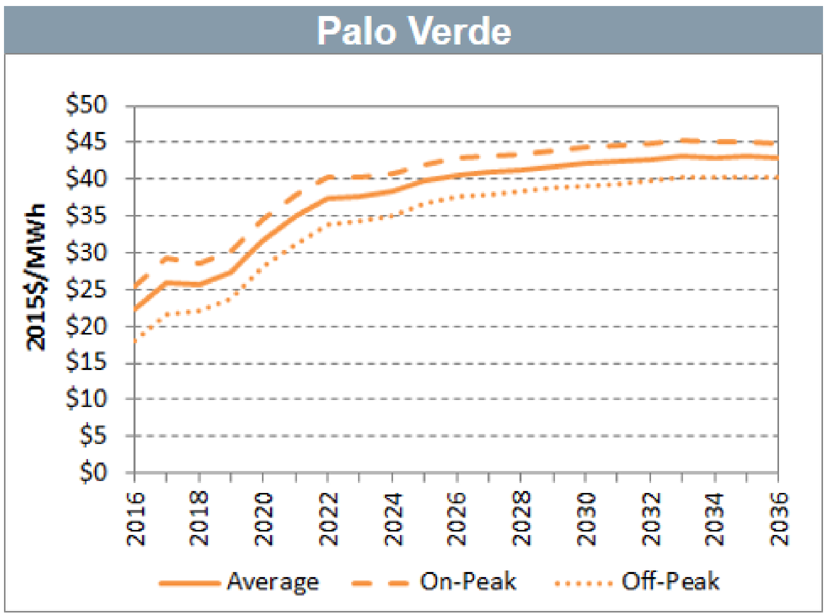
California

- Projections for the currently oversupplied AB32 trading market increase in line with auction price floor through 2020 – beyond this time the program continues to meet the State's 2030 goals of 40% reduction over 1990 levels.

Baseline Zonal Power Prices – Four Corners and Palo Verde

- Baseline power prices in the region projected to increase through much of the forecast period due to:
  - Natural gas prices increasing from current levels
  - The introduction of a price on carbon in the U.S. in 2022 which increases through 2030
  - Steady load growth in New Mexico and southwest (CAAGR ~0.6 percent over forecast period)

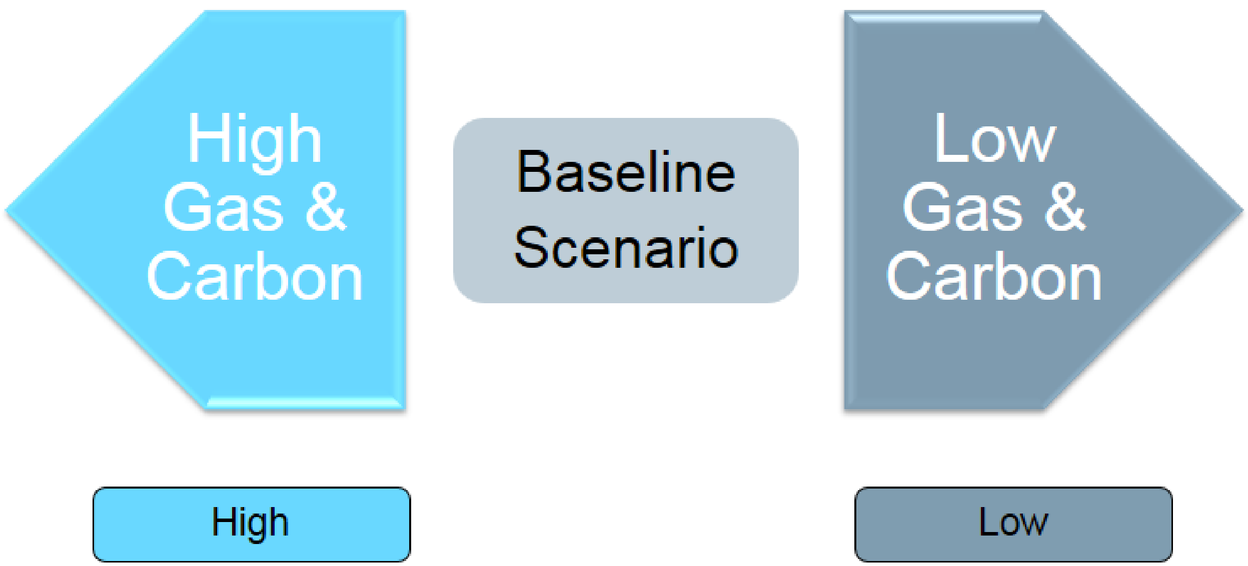




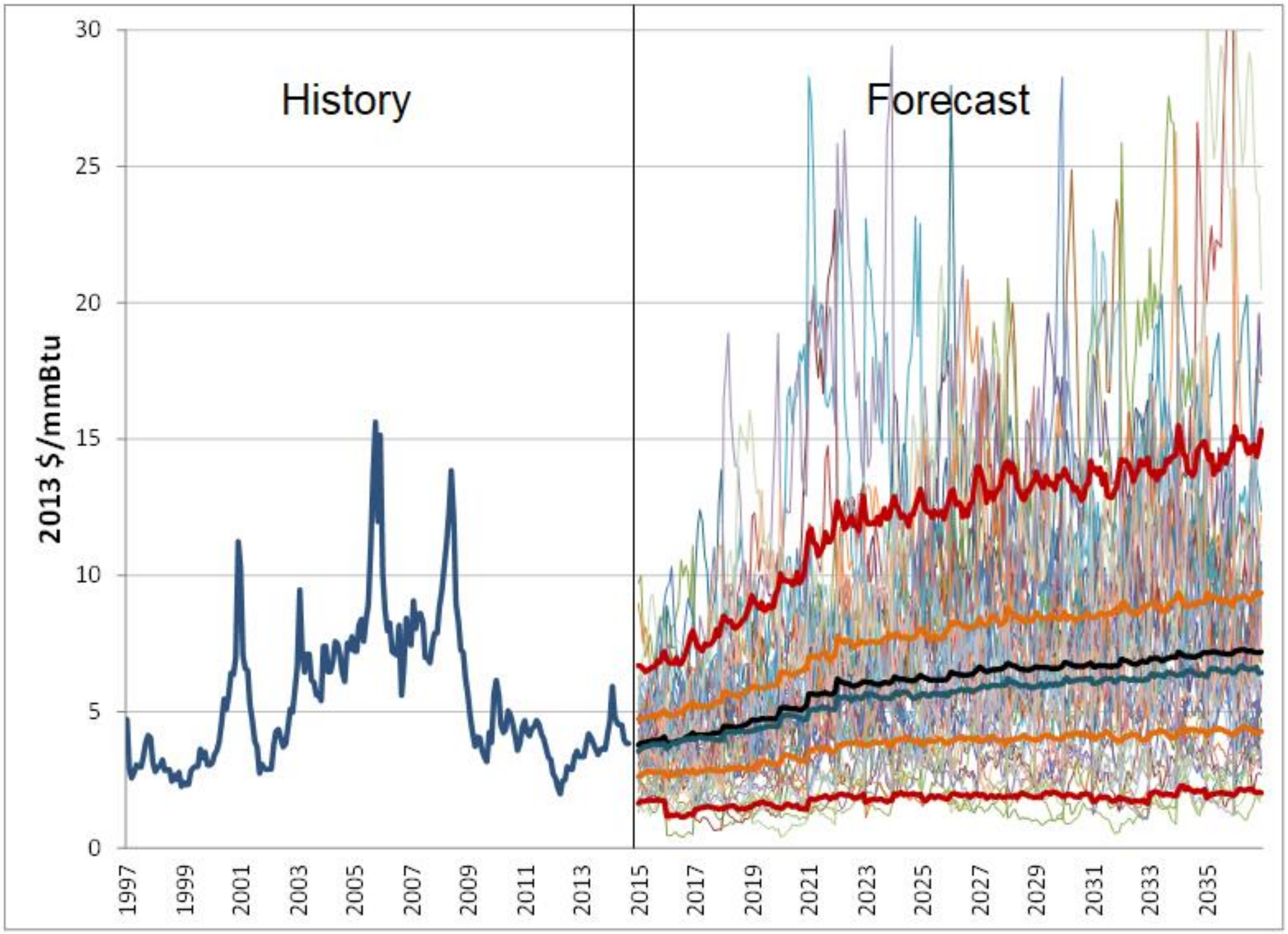
Alternate Scenarios

Scenario Development for IRP Analysis

- Pace Global and PNM identified natural gas price and carbon price as the two major drivers of portfolio performance.
- High natural gas and carbon and low gas and carbon price assumptions drove the two alternate scenarios.
- Stochastic distributions were used to develop the high and low assumptions based on a one standard deviation delta from the baseline.



Stochastic Distributions Inform High and Low Scenarios (Illustrative Example)

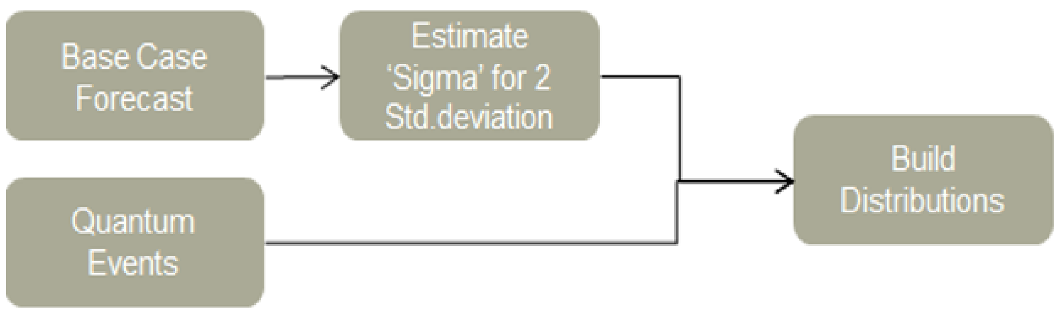


Carbon Stochastics Developed in Absence of Historical Data – Reflecting CPP

- The technique to develop carbon costs distributions, unlike the previous variables, is based on the "expert-opinion" based projections due to lack of historical data.

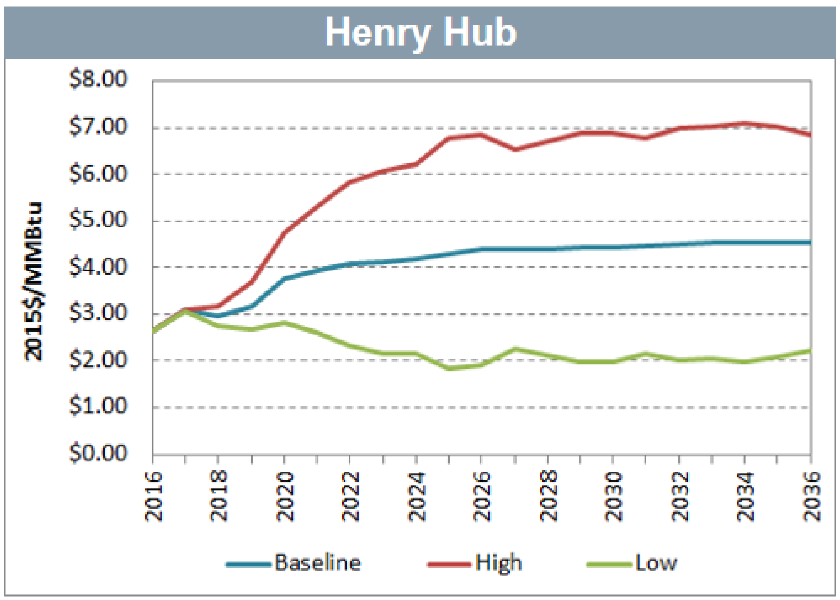
  1. Stress test analysis to determine range of shadow prices under the CPP – high / low
  2. High and low treated as 16th, 50th and 84th percentiles from which statistical techniques are used to calculate the standard deviation values.
  3. The distributions are then adjusted to incorporate probabilities such as " the probability of a CO2 program not taking effect", "greater chance of a nation-wide CO2 regime starting in, say 2022" etc.

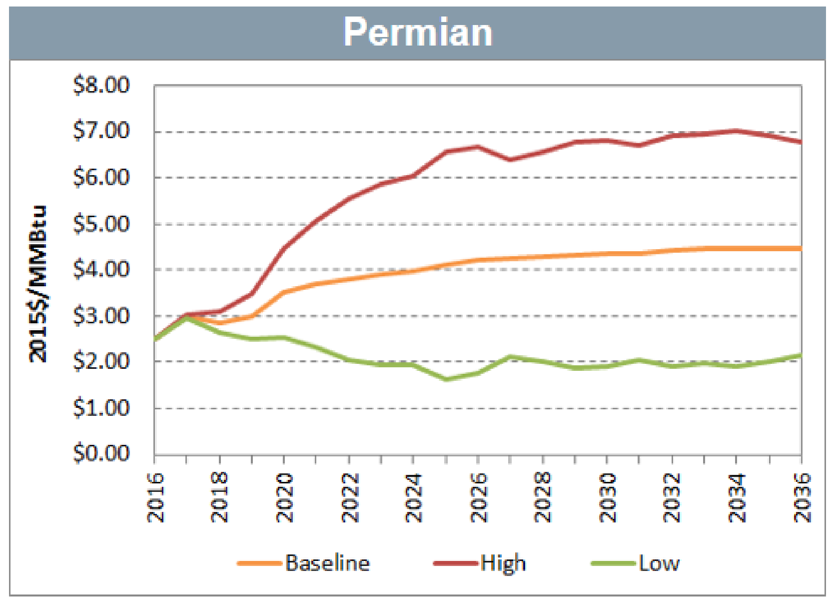
Method for Distribution Generation



High and Low Natural Gas Prices – Henry Hub and Permian Basin

- High natural gas prices could result from restrictions on gas production (i.e. fracking regulations) increasing the cost to produce, greater than expected LNG and pipeline exports, and/or a stronger economy driving demand.
- Lower natural gas prices could result from energy storage technology breakthrough (resulting in lower gas demand), a weaker economy, or lower export scenarios.

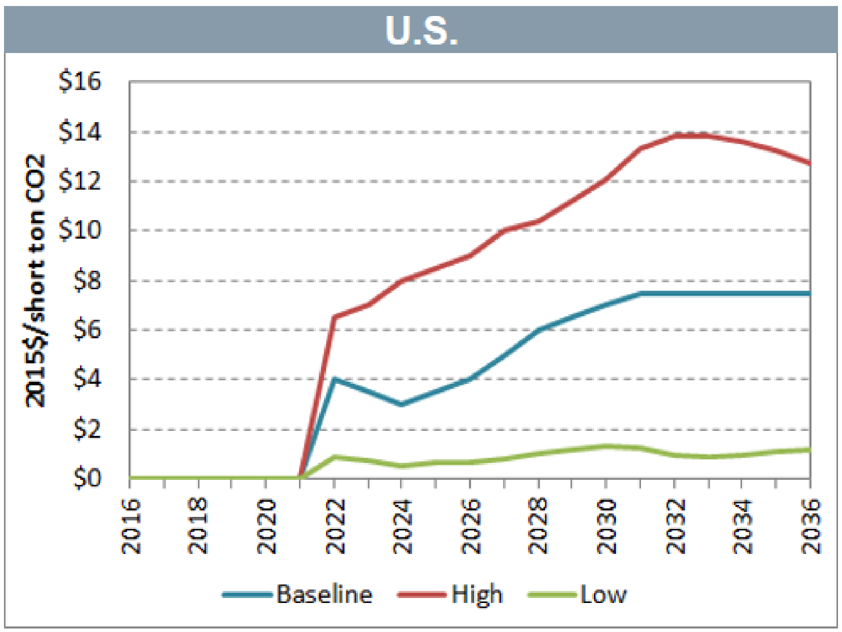


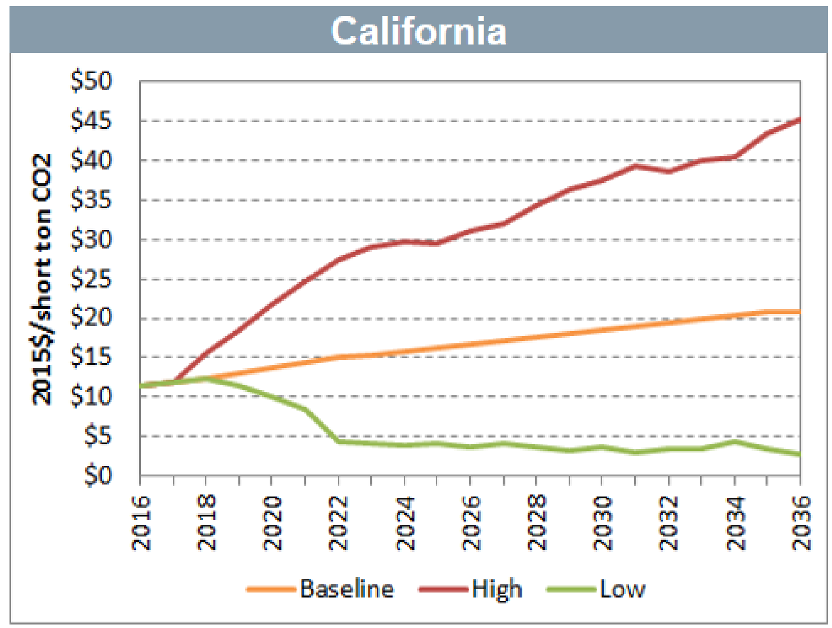


High and Low Carbon Prices – U.S. and California

- The high carbon price scenario reflects the possibility of high gas price trajectory due to less efficient implementation of the CPP (less interstate trading), high natural gas prices, speculation driving prices above actual cost to comply.

- The low carbon price scenario could result from low natural gas prices, a very active national trading market where most low cost states decide on a national interstate trading scheme, and/or greater than expected retirements of coal and other gas units "affected" under the CPP.





High and Low Carbon Prices – U.S. and California

- The high carbon price scenario reflects the possibility of high gas price trajectory due to less efficient implementation of the CPP (less interstate trading), high natural gas prices, speculation driving prices above actual cost to comply.
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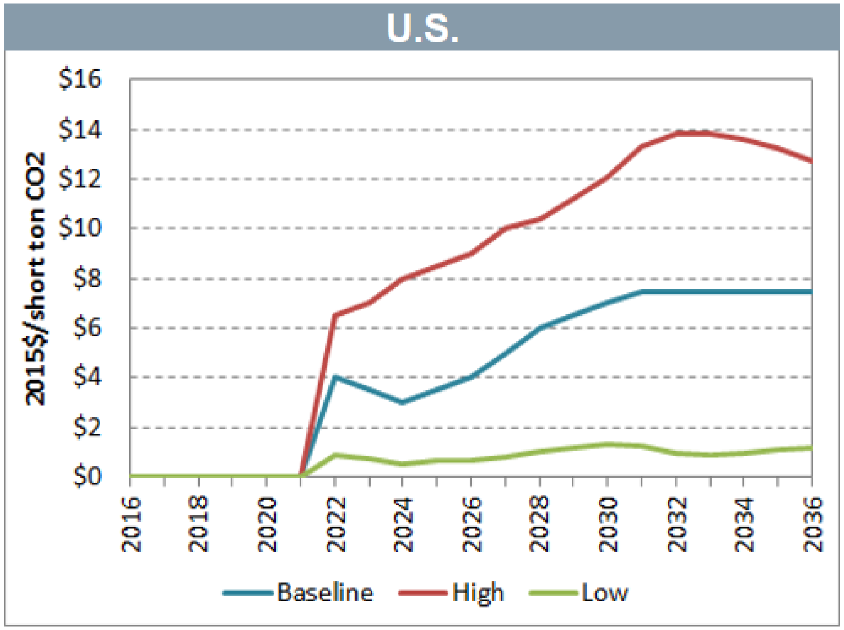
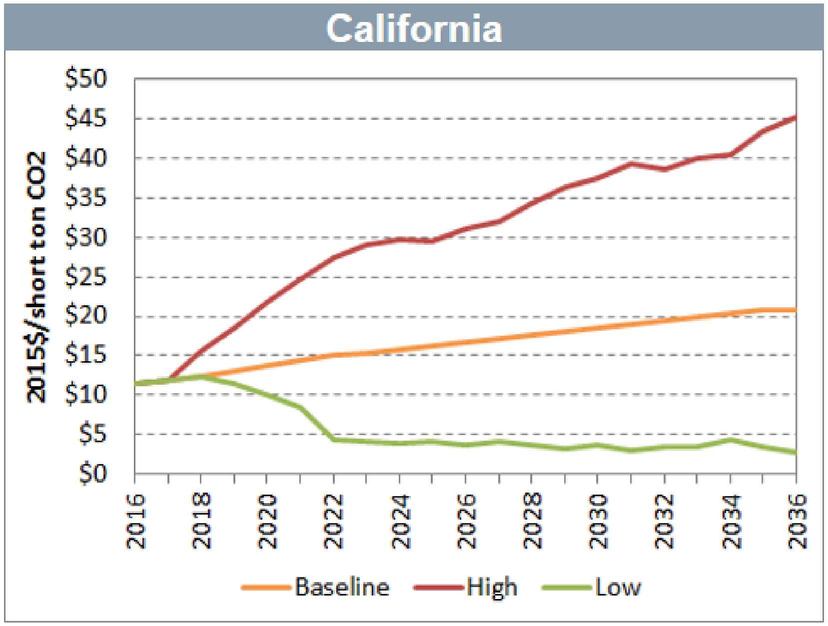




SIEMENS

Questions

APPENDIX J. COST AND PERFORMANCE DATA FOR PNM'S EXISTING GENERATING RESOURCES

Table 22. Resource Performance Data - Existing Resources I

Metric	San Juan				Four Corners		Palo Verde			Luna	Afton
	Unit 1	Unit 2	Unit 3	Unit 4	Unit 4	Unit 5	Unit 1 Owned	Unit 2 Owned	Unit 3		
Facility Output (MW)	170	170	248	195*	100	100	124	30	134	185	230
Peak Contribution	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Estimate Heat Rate @ Max Output (Btu/kWh)	10,786	10,786	10,475	10,669	10,114	10,114	10,300	10,300	10,300	7,098	7,029
Expected Capacity Factor	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%
Forced Outage Rate	10.5-14.5%	10.5-14.5%	10.5-14.5%	10.5-14.5%	20%	20%	2%	2%	2%	3%	3%
Emission Rates											
CO_2 Rate (lb/MWh)	2,182	2,103	2,182	2,182	1,864	1,864	0	0	0	926	930
CO Rate (lb/MWh)	2.67	4.29	2.67	2.67	n/a	n/a	0	0	0	0.05	0.14
SO_2 Rate (lb/MWh)	0.65	0.54	0.51	0.51	1.20	1.20	0	0	0	0	0
NO_x Rate (lb/MWh)	2.81	2.75	2.62	2.62	4.72	4.72	0	0	0	0.09	0.13
Hg Rate (lb/GWh)	0.001	0.001	0.001	0.001	0.006	0.006	0	0	0	0	0
PM_{10} Rate (lb/MWh)	0.033	0.033	0.034	0.034	0.068	0.068	0	0	0	0.026	0.062
Water Usage (gal/MWh)	647	647	647	647	496	496	18	18	18	202	85
Construction Time (months)											
Expected Retirement Date	Scenario	Year End 2017	Year End 2017	Scenario	Scenario	Scenario	2045	2046	2047	2042	2042
Facility Life (years)	Scenario	2	2	Scenario	Scenario	Scenario	28	29	30	30	30

* Facility output will increase to 327 MW beginning in 2018

Table 23. Resource Cost & Financial Data - Existing Resources I (continued)

Metric	San Juan				Four Corners		Palo Verde			Luna	Afton
	Unit 1	Unit 2	Unit 3	Unit 4	Unit 4	Unit 5	Unit 1 Owned	Unit 2 Owned	Unit 3		
Facility Output (MW)	170	170	248	195*	100	100	134	134	134	185	230
Utility-Owned											
Preliminary Revenue Requirements - Capital Expenditures (NPV 1,000$)	*see summary table for capital expenditures by plant*										
Cost of Capital	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Reference Year Dollars	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017
Fixed O&M Costs ($/kW/yr)											
Base O&M (5-year average)	*see summary table for O&M expenses by plant*										
Transmission											
Fuel Handling/Gas Reservation											
Property Taxes											
Total											
Variable O&M Costs ($/MWh)											
Base O&M	*included in FOM*										
Integration Costs											
Total											
PPA											
Energy Price ($/MWh)											
Base Energy Price											
Transmission Service											
Integration Costs											
Total											
Reference Year Dollars											
Annual Escalation											

* Facility output will increase to 327 MW beginning in 2018

Table 24. Resource Performance Data - Existing Resources II

Metric	Lordsburg		La Luz	Reeves			Rio Bravo	Solar		Valencia	NM Wind Energy Center	Red Mesa Wind	Dale Burgett
	Unit 1	Unit 2		Unit 1	Unit 2	Unit 3		Fixed Tilt	Tracking				
Facility Output (MW)	40	40	40	44	44	66	138	40	67	150	200	102	8
Peak Contribution	100%	100%	100%	100%	100%	100%	100%	55%	71%	100%	5%	5%	56%
Estimate Heat Rate @ Max Output (Btu/kWh)	9,596	9,576	9,485	12,039	12,039	12,039	10,284			10,177			
Expected Capacity Factor	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-100%	0-28%	0-33%	0-100%	0-100%	0-100%	0-100%
Forced Outage Rate	3%	3%	3%	3%	3%	3%	3%			3%			
Emission Rates													
CO_2 Rate (lb/MWh)	1,379	1,379	1,166	1,556	1,556	1,556	1,411	-	-	1,378	-	-	-
CO Rate (lb/MWh)	0.724	0.724	0.009	0.72	0.72	0.72	0.01	-	-	0.15	-	-	-
SO_2 Rate (lb/MWh)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-	-	0.01	-	-	-
NO_x Rate (lb/MWh)	1.20	1.20	0.09	3.09	3.09	3.09	0.40	-	-	0.40	-	-	-
Hg Rate (lb/GWh)	*	*	*	*	*	*	*	-	-	*	-	-	-
PM_{10} Rate (lb/MWh)	0.077	0.077	0.027	0.095	0.095	0.095	0.050	-	-	0.198	-	-	-
Water Usage (gal/MWh)	100	100	100	619	619	619	10	-	-	10	-	-	-
Construction Time (months)													
Expected Retirement	After 2036	After 2036	After 2036	After 2036	After 2036	After 2036	After 2036	After 2036	After 2036				
Contract Expiration										May 2028	July 2028	Dec. 2035	Jan. 2034
Facility Life (years)	40	40	40	Sensitivity	Sensitivity	Sensitivity	40	25	25				

* Do not monitor

Table 25. Resource Cost & Financial Data - Existing Resources II (continued)

Metric	Lordsburg		La Luz	Reeves			Rio Bravo	Solar		Valencia	NM Wind Energy Center	Red Mesa Wind	Dale Burgett
	Unit 1	Unit 2		Unit 1	Unit 2	Unit 3		Fixed Tilt	Tracking				
Facility Output (MW)	40	40	40	44	44	66	138	40	67	150	200	102	0
Utility-Owned													
Preliminary Revenue Requirements - Capital Expenditures (NPV 1,000$)	*see summary table for capital expenditures and O&M by plant*												
Cost of Capital	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Reference Year Dollars	2017	2017	2017	2017	2017	2017	2017	2017	2017				
5-Year Fixed O&M ($/kWh/yr)													
Base O&M													
Transmission													
Gas Reservation													
Property Taxes													
Total													
Integration													
Total													
PPA													
Demand										$8.15			
Fixed O&M										$1.79			
Gas Reservation Fee										$1.03			
Total ($/kW/mo)										$10.97	$-	$-	$-
Variable/Energy Price (non-fuel) ($/MWh)													
Base Energy Price											$27.25	$29.05	$105.73
Transmission Service													
Variable O&M										$6.72			
Integration													
Total										$6.72	$27.25	$29.05	$105.73
Reference Year Dollars										2017	2017	2017	2017
Annual Escalation											Fixed	2.0%	Fixed

* Do not monitor

APPENDIX K. COST AND PERFORMANCE DATA FOR NEW SUPPLY-SIDE RESOURCE OPTIONS

Table 26. New Resource Alternatives Performance Data - Conventional Resources

Metric	Aeroderivative		Gas Turbine		Reciprocating Engines	Rio Bravo Expansion	Combined Cycle		Palo Verde		Battery Storage	
	Small	Large	Mid	Large			New Build	Existing	Unit 1	Unit 2	2-Hour	4-Hour
Expected Facility Output (MW @ 4000 ft, 90 F)	40	85	140	187	41	210	289	250	104	10	2	40
Estimated ELCC	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Tier 2: 80 MW												
Tier 3: 120 MW												
Tier 4: >80 MW												
Estimate Heat Rate @ Max Output (Btu/kWh)	9,800	9,800	10,400	9,600	8,800	6,999	7,200	7,000	10,300	10,300	*	*
Expected Capacity Factor	5-15%	5-15%	5-25%	5-25%	5-65%	25-65%	25-65%	25-65%	0-100%	0-100%	0-15%	0-15%
Forced Outage Rate	3%	3%	3%	3%	3%	5%	5%	5%	2%	2%	2.0%	2.0%
Emission Rates												
CO_2 Rate (lb/MWh)	1,140	1,115	1,300	1,300	980	845	845	845	-	-	-	-
CO Rate (lb/MWh)	0.0892	0.2800	0.1800	0.1800	0.2600	0.1200	0.1200	0.1200	-	-	-	-
SO_2 Rate (lb/MWh)	0.1313	-	-	-	-	-	-	-	-	-	-	-
NO_x Rate (lb/MWh)	0.0098	0.1100	0.3900	0.3900	3.6500	0.0800	0.0800	0.0800	-	-	-	-
Hg Rate (lb/GWh)	-	-	-	-	-	-	-	-	0.000	0.000	-	-
PM_{10} Rate (lb/MWh)	0.0838	-	-	-	-	1.0000	1.0000	1.0000	0.000	0.000	-	-
Water Usage (gal/MWh)	100	150	50	50	150	150	150	600	18	18	-	-
Construction Time (months)	9	12	12	12	12	24	24	24			24	24
Contract Expiration	2020	2020	2020	2020	2020	2021	2022	2021	2024	2023	2021	2021
Facility Life (years)	40	40	40	40	40	40	40	40	29	29	30	30

* Charging technology

Table 27. New Resource Alternatives Cost & Financial Data - Conventional Resources (Continued)

Metric	Aeroderivative		Gas Turbine		Reciprocating Engines	Rio Bravo Expansion	Combined Cycle		Palo Verde		Battery Storage	
	Small	Large	Mid	Large			New Build	Existing	Unit 1	Unit 2	2-Hour	4-Hour
Expected Facility Output (MW @ 4000 ft, 90 F)	40	85	140	187	41	289	210	250	104	10	2	40
Investment Tax Credit - Federal	-	-	-	-	-	-	-	-	-	-	-	-
Production Tax Credit - Federal	No	No	No	No	No	No	No	No	No	No	No	No
Production Tax Credit - State	No	No	No	No	No	No	No	No	No	No	No	No
Proxy Property Tax	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	1.3%	1.3%	1.3%	2.7%	2.7%
Utility Ownership												
Capital Cost												
Construction Cost	$38,000	$78,000	$116,000	$126,000	43,500	$145,200	$258,000	$-	$-	$-	$3,700	$114,400
Transmission Upgrades/ Interconnection	$3,000	$5,000	$5,000	$5,000	$2,500	$5,000	$10,000	$-	$-	$-	$-	$-
AFUDC	$1,512	$3,043	$4,395	$4,729	$1,678	$10,267	$17,553	$-	$-	$-	$84	$2,583
Owners' Costs	$3,500	$4,500	$5,400	$5,000	$2,250	$7,500	$10,200	$-	$-	$-	$-	$-
Total	**$46,012**	**$90,543**	**$130,795**	**$140,729**	**$49,928**	**$167,967**	**$295,753**	**$175,000**	**$260,000**	**$25,000**	**$3,784**	**$116,983**
Total per kW	$1,150	$1,065	$934	$753	$1,218	$800	$1,023	$700	$2,500	$2,500	$1,892	$2,925
Revenue Requirements (Capital Only)	$55,761	$109,492	$161,188	$174,395	$61,103	$222,764	$396,160	$248,280			$4,680	$144,707
	$56,314	*$110,480*	*$162,424*	*$176,925*	*$122,292*			*$247,489*			*$5,606*	*$173,326*
Cost of Capital	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Reference Year	**2017**	**2017**	**2017**	**2017**	**2017**	**2017**	**2017**	**2017**	**2024**	**2023**	**2017**	**2017**
Fixed O&M ($/kW/yr)												
Base O&M	$17.40	$16.00	$6.250	$4.90	$4.90	$22.20	$20.00	$22.00			$28.00	$39.00
Gas Reservation	$26.00	$26.00	$26.00	$26.00	$26.00	$18.10	$26.00	$26.00			$-	$-
Transmission Service	$-	$-	$-	$-	$-	$-	$-	$40.80			$-	$-
Property Taxes	$-	$-	$-	$-	$-	$-	$-	$-			$-	$-
Total	**$43.40**	**$42.00**	**$32.30**	**$30.90**	**$30.90**	**$40.30**	**$46.00**	**$88.80**			**$28.00**	**$39.00**
Variable O&M												
Base O&M	$5.26	$4.64	$4.00	$2.56	$2.21	$2.75	$2.57	$2.55	$-	$-	*	*
Integration	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-
Total	**$5.26**	**$4.64**	**$4.00**	**$2.56**	**$2.21**	**$2.75**	**$2.57**	**$2.55**	**$-**	**$-**	**$-**	**$-**

* Charging technology

Table 28. New Resource Alternatives Cost & Financial Data – Combined Cycle Sensitivity

Metric	Combined Cycle – H Series (New Build)	Combined Cycle – H Series ½ Owner	Combined Cycle – H Series 1/3 Owner	Combined Cycle – H Series 1/6 Owner
Expected Facility Output (MW @30 ft, 90 F)	405	202.5	135	67.5
Estimated ELCC	100%	100%	100%	100%
Tier 2: 80 MW				
Tier 3: 120 MW				
Tier 4: >80 MW				
Estimate Heat Rate @ Max Output (Btu/kWh)	6,550	6,550	6,550	6,550
Expected Capacity Factor	25-65%	25-65%	25-65%	25-65%
Forced Outage Rate	5%	5%	5%	5%
CO_2 Rate (lb/MWh)	845	845	845	845
CO Rate (lb/MWh)	0.0310	0.0310	0.0310	0.0310
SO_2 Rate (lb/MWh)	-	-	-	-
NO_x Rate (lb/MWh)	0.0070	0.0070	0.0070	0.0070
Hg Rate (lb/GWh)	-	-	-	-
PM_{10} Rate (lb/MWh)	1.0000	1.0000	1.0000	1.0000
Water Usage (gal/MWh)	150	150	150	150
Construction Time (months)	24	24	24	24
Contract Expiration	2022	2022	2022	2022
Facility Life (years)	40	40	40	40

Table 29. New Resource Alternatives Cost & Financial Data – Combined Cycle Sensitivity (Continued)

Metric	Combined Cycle – H Series (New Build)	Combined Cycle – H Series ½ Owner	Combined Cycle – H Series 1/3 Owner	Combined Cycle – H Series 1/6 Owner
Expected Facility Output (MW @ 30 ft, 90 F)	405	202.5	135	67.5
Investment Tax Credit - Federal	-	-	-	-
Production Tax Credit - Federal	No	No	No	No
Production Tax Credit - State	No	No	No	No
Proxy Property Tax	2.7%	2.7%	2.7%	2.7%
Construction Cost	$362,566	$181,283	$120,855	$60,428
Transmission Upgrades/ Interconnection	$10,000	$5,000	$3,333	$1,667
AFUDC	$24,416	$12,208	$8,139	$4,069
Owners' Costs	$10,200	$5,100	$3,400	$1,700
Total	$407,183	$203,591	$135,728	$67,864
Total per kW	$1,005	$1,005	$1,005	$1,005
Revenue Requirements (Capital Only)	$532,298	$266,149	$177,433	$88,716
Cost of Capital	7.7%	7.7%		
Reference Year	**2017**	**2017**	**2017**	**2017**
Base Fixed O&M	$18.46	$18.46	$18.46	$18.46
Gas Reservation	$26.00	$26.00	$26.00	$26.00
Transmission Service	$-	$-	$-	$-
Property Taxes	$-	$-	$-	$-
Total	**$44.50**	**$44.50**	**$44.50**	**$44.50**
Base Variable O&M	$2.43	$2.43	$2.43	$2.43
Integration	$-	$-	$-	$-
Total	**$2.43**	**$2.43**	**$2.43**	**$2.43**

Table 30. New Resource Alternatives Performance Data - Renewable Resources

Metric	Solar Photovoltaic Tracking			Solar Power Tower	Solar Photovoltaic for RPS	Wind for RPS	Wind	Geothermal
Nameplate Facility Output (MW)	10	50	100	100	50		100	15
Estimated ELCC					71%	0%	5%	100%
Tier 2: 80 MW	71%	71%	71%	100%				
Tier 3: 140 MW	52%	52%	52%	100%				
Tier 4: >80 MW	20%	20%	20%	100%				
Estimate Heat Rate @ Max Output (Btu/kWh)								
Expected Capacity Factor	33%	33%	33%	45%	33%	49%	40%	85%
Forced Outage Rate	0%	0%	0%	0%	0%	0%	0%	0%
Emission Rates								
CO_2 Rate (lb/MWh)	-	-	-	-	-	-	-	-
CO Rate (lb/MWh)	-	-	-	-	-	-	-	-
SO_2 Rate (lb/MWh)	-	-	-	-	-	-	-	-
NO_x Rate (lb/MWh)	-	-	-	-	-	-	-	-
Hg Rate (lb/GWh)	-	-	-	-	-	-	-	-
PM_{10} Rate (lb/MWh)	-	-	-	600	-	-	-	100
Water Usage (gal/MWh)	9	15	15	24	15	12	24	24
Construction Time (months)	**2018**	**2019**	**2019**	**2020**	**2020**	**2019**	**2021**	**2021**
Expected Retirement Date	30	30	30	30	30	25	25	30
Facility Life (years)	10	50	99	100	50		100	15
Nameplate Facility Output (MW)	10	50	99	100	50		100	15
Investment Tax Credit - Federal	Yes	Yes	Yes	Yes	Yes	-	-	10%
Production Tax Credit - Federal						Yes	Yes	Yes
Production Tax Credit - State	No	No	No	No	No	No	No	No
Proxy Property Tax	2.6%	2.6%	2.6%					

Table 31. New Resource Alternatives Cost & Financial Data - Renewable Resources (Continued)

Metric	Solar Photovoltaic Tracking			Solar Power Tower	Solar Photovoltaic for RPS	Wind for RPS	Wind	Geothermal
Utility Ownership								
Capital Cost ($1,000s)								
Construction Cost	$12,494	$61,499	$122,997		$63,718			
Transmission	$776	$3,000	$6,000		$3,880			
AFUDC	$250	$1,190	$2,380		$1,536			
Owners' Costs	$890	$3,033	$6,066		$3,200			
Total	$14,409	$68,722	$137,444		$72,334			
Total per kW	$1,441	$1,388	$1,388		$1,447			
Revenue Requirements (Capital Only)	$16,859	$81,117	$162,234		$76,616			
Cost of Capital	7.7%	7.7%	7.7%		7.7%			
Reference Year Dollars	2017	2017	2017		2017			
Fixed O&M ($/kW/yr)								
Base O&M	$10.0	$10.0	$10.0		$10.5			
Property Taxes					$13.0			
Total	$-	$-	$-		$23.5			
Variable O&M ($/MWh)								
Base O&M	$-	$-	$-		$-			
Integration	$1.70	$1.70	$1.70		$1.70			
Total	$1.70	$1.70	$1.70		$1.70			
PPA								
Energy Price ($/MWh)								
Base Energy Price				$185.00			$34.75	$65.30
Transmission Upgrades				$-			$7.00	$17.91
Interconnection							included	included
PPA Administration							$1.04	$1.79
Integration Costs				$-			$4.06	$-
Total				**$185.00**			**$46.85**	**$85.00**
Reference Year Dollars	2016	2016	2016	2016			2019	2021
Annual Escalation				none	*see renewable costs sheet*			

Table 32. New Resource Alternatives Performance Data - Renewable Resource Costs

Metric/Year	Solar Power Tower 10-Hour Storage	Wind for RPS	Wind	Data Center	
				Solar PV	Wind
Nameplate Facility Output (MW)	**100**	**200**	**100**	**Varies**	**Varies**
2017	$185.00			$47.50	$46.10
2018	$185.00			$47.50	$46.10
2019	$185.00	$27.25	$46.85	$47.50	$46.10
2020	$185.00	$27.25	$46.93	$47.50	$46.10
2021	$185.00	$27.25	$47.01	$47.50	$46.10
2022	$185.00	$27.25	$47.09	$47.50	$46.10
2023	$185.00	$27.25	$47.17	$47.50	$46.10
2024	$185.00	$27.25	$47.25	$47.50	$46.10
2025	$185.00	$27.25	$47.33	$47.50	$46.10
2026	$185.00	$27.25	$47.41	$47.50	$46.10
2027	$185.00	$27.25	$47.50	$47.50	$46.10
2028	$185.00	$27.25	$47.58	$47.50	$46.10
2029	$185.00	$27.25	$47.67	$47.50	$46.10
2030	$185.00	$27.25	$47.76	$47.50	$46.10
2031	$185.00	$27.25	$47.85	$47.50	$46.10
2032	$185.00	$27.25	$47.94	$47.50	$46.10
2033	$185.00	$27.25	$48.03	$47.50	$46.10
2034	$185.00	$27.25	$48.13	$47.50	$46.10
2035	$185.00	$27.25	$48.22	$47.50	$46.10
2036	$185.00	$27.25	$48.32	$47.50	$46.10

Effective Load Carrying Capacity (ELCC)

The effective load carrying capability (ELCC) of a generator represents its ability to provide full capacity at all times. Dispatchable generators such as gas turbines or combined cycles have high ELCC values because they can be called upon to provide 100% power most of the time. Intermittent resources (nondispatchable) such as solar photovoltaics or wind do not exhibit as high ELCCs since they may not provide maximum capacity at the same time of PNM's peak. Also, capacity must be available to meet demand that exceeds the power provided by baseload and available renewable energy generators. As the sun sets, the solar resource powerbecomes unavailable, therefore if there is no demand reduction, or the demand reduction is less than solar resource supply reduction, the peak need for non-solar resources may shift later than the peak hour of maximum customer demand. The demand that must be served by dispatchable resources after the renewable and other non-dispatchable resource availability is referred to as the net demand.

Net demand is important because increasing solar penetration levels can shift the peak hour and impact portfolio resource selection. As such, assigning ELCC values for all existing and future renewable resources is needed for accurate resource modeling. PNM relies on manufacturer data as well as historical data to set the ELCCs for solar. On PNM's existing system, approximately 65 MW of private PV systems and 107 MW of universal solar are installed. PNM also anticipates an additional 30 MW of universal solar associated with the data center customer and 50 MW for 2020 RPS compliance by the end of 2019.

Because of the lack of historical data for the private PV systems, PNM relied on NREL data to determine the ELCC for fixed tilt PV systems. This assumption is expected to change once PNM has received enough historical data to reflect a more accurate range. Current installations of Integrated Data Recorders have only been in place for over a year and PNM expects to receive more data before determining if the ELCC proxy used from NREL is accurate enough for continued use. Because of the lack of historical data to create a trend for the purposes of this sensitivity PNM maintained a 4:00 PM, 56% ELCC assumption for private solar.

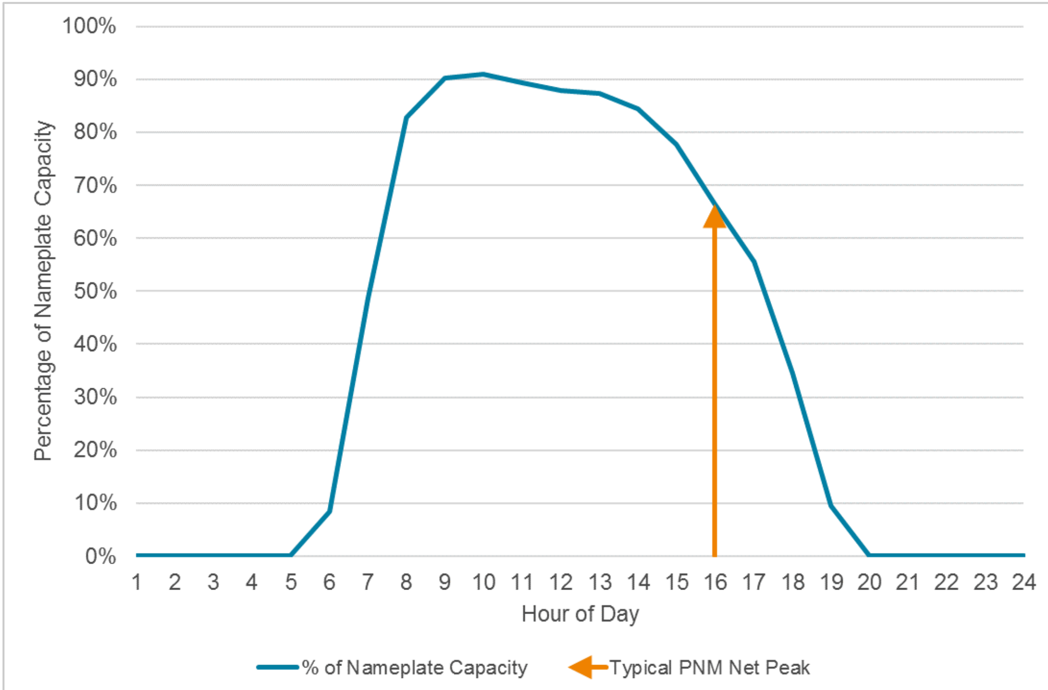
For universal solar (both fixed tilt and tracking); PNM relies on a mixture of historical data and manufacturer bids from a previous RFP to determine the starting point of the ELCC. PNM uses the same ELCC for existing installations on PNM's system: 56% for fixed tilt and 76% for tracking sytems at 4:00 PM. While this is not enough to shift the net peak hour today; by 2020 enough solar will be installed on PNM's system to shift the net peak hour by two hours

PNM examined the hourly load forecast to determine when the net peak hour occurs (Table 33) combined with the solar energy production for the peak month (Figure 9). Using this information, PNM developed solar tiers and the appropriate ELCCs to use for each tier. By 2023, universal solar additions are assumed to have a 35% ELCC that diminishes to 9% after 270 MW of tier 3 universal solar additions.

Table 33. 2018 Solar Energy Production Over Peak Hours

Hour	Hour Ending MST	Hour Ending MDT	2018 PNM Peak	Previous Hour MW Change	Solar PV Peak Contribution	Total Solar PV Needed to Shift Peak	Incremental Solar PV Needed to Shift Peak	Peak	Solar PV Tier
1	1:00 AM	2:00 AM	1,065		0%				
2	2:00 AM	3:00 AM	1,014		0%				
3	3:00 AM	4:00 AM	988		0%				
4	4:00 AM	5:00 AM	973		0%				
5	5:00 AM	6:00 AM	975		0%				
6	6:00 AM	7:00 AM	1,045		8%				
7	7:00 AM	8:00 AM	1,140		49%				
8	8:00 AM	9:00 AM	1,236		83%				
9	9:00 AM	10:00 AM	1,361		90%				
10	10:00 AM	11:00 AM	1,474		91%				
11	11:00 AM	12:00 PM	1,582		89%				
12	12:00 PM	1:00 PM	1,663		88%				
13	1:00 PM	2:00 PM	1,756		87%				
14	2:00 PM	3:00 PM	1,828		84%				
15	3:00 PM	4:00 PM	1,869		78%				
16	**4:00 PM**	**5:00 PM**	**1,900**	**31.1**	**67%**	**62**	**62**	**Peak Hour**	**Tier 1**
17	**5:00 PM**	**6:00 PM**	**1,877**	**-23.1**	**56%**	**161**	**100**	**Peak Hour +1**	**Tier 2**
18	**6:00 PM**	**7:00 PM**	**1,817**	**-59.5**	**35%**	**431**	**270**	**Peak Hour +2**	**Tier 3**
19	7:00 PM	8:00 PM	1,683	-134.3	9%	0	0	Peak Hour +3	No ELCC
20	8:00 PM	9:00 PM	1,641	-42.4	0%	0	0	Peak Hour +4	No ELCC
21	9:00 PM	10:00 PM	1,576		0%				
22	10:00 PM	11:00 PM	1,419		0%				
23	11:00 PM	12:00 AM	1,263		0%				
24	12:00 AM	1:00 AM	1,159		0%				

Figure 9. Solar Energy Production by Hour



APPENDIX L. TOP RANKED PORTFOLIOS FOR EACH OF 21 SJGS CONTINUES SCENARIOS

Table 34. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = LOW, GAS = LOW, CO_2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$6,442,966,234
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,216,803	971	1,471	24.57
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,826,392	890	1,290	$6,439,770,742
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,547,834	821	1,137	$26,871,633
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,413,544	779	1,061	74,366,833
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	2,295,063	747	985	$21,723,545
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	25.24	2,586,265	837	1,004	864
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
2024		24.54	2,645,776	866	1,022	1078
2025		24.06	2,555,075	841	996	**20-Year Freshwater (Bn of Gal)**
2026		23.65	2,484,900	840	990	42.868
2027		23.02	2,548,766	853	1,012	**Outside Adjustment 1**
2028	Reciprocating Engines (41 MW)	16.09	2,508,139	843	1,001	$0
2029		15.41	2,406,776	825	974	**Outside Adjustment 2**
2030		14.30	2,400,781	838	980	$0
2031	Reciprocating Engines (41 MW)	14.85	2,436,124	830	989	**Outside Model Adjustment 3**
2032	Aeroderivative (40 MW)	15.40	2,432,784	834	988	$0
2033	Aeroderivative (40 MW)	15.96	2,452,182	843	995	**Outside Model Adjustment 4**
2034		14.61	2,444,855	839	992	$0
2035	Aeroderivative (40 MW)	14.95	2,412,292	828	985	**Total Optimized NPV + Adjustments**
2036	Solar PV Large (100 MW)	14.66	2,466,467	841	986	$6,442,966,234
						Average Risk NPV + Adjustments
						$6,439,770,742

Table 35. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = LOW, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$6,618,698,875
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,213,530	972	1,472	24.70
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,818,348	892	1,292	$6,618,642,974
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,535,775	824	1,138	$50,367,651
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,403,789	781	1,062	74,770,652
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	2,290,912	751	987	$132,397,569
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	25.24	2,597,847	846	1,015	868
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
2024		24.54	2,644,379	871	1,027	1082
2025		24.06	2,597,191	857	1,019	**20-Year Freshwater (Bn of Gal)**
2026		23.65	2,489,091	847	998	43.165
2027		23.02	2,538,641	856	1,013	**Outside Adjustment 1**
2028	Reciprocating Engines (41 MW)	16.09	2,497,831	846	1,002	$0
2029		15.41	2,415,365	833	983	**Outside Adjustment 2**
2030		14.30	2,404,500	844	986	$0
2031	Reciprocating Engines (41 MW)	14.85	2,426,032	834	990	**Outside Model Adjustment 3**
2032	Aeroderivative (40 MW)	15.40	2,426,667	838	990	$0
2033	Aeroderivative (40 MW)	15.96	2,453,473	848	1,000	**Outside Model Adjustment 4**
2034		14.61	2,440,197	844	995	$0
2035	Aeroderivative (40 MW)	14.95	2,403,923	831	987	**Total Optimized NPV + Adjustments**
2036	Solar PV Large (100 MW)	14.66	2,458,612	844	987	$6,618,698,875
						Average Risk NPV + Adjustments
						$6,618,642,974

Table 36. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = LOW, GAS = HIGH, CO_2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,212	1,301	1,682	$6,800,808,469
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,209,340	973	1,473	24.69
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,813,106	894	1,293	$6,802,949,822
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,532,923	824	1,138	$76,913,716
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,400,092	782	1,063	74,838,244
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	2,288,109	751	987	$251,846,552
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	25.24	2,593,166	847	1,015	869
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
2024		24.54	2,639,874	872	1,028	1082
2025		24.06	2,592,968	858	1,019	**20-Year Freshwater (Bn of Gal)**
2026		23.65	2,484,988	848	998	43.216
2027		23.02	2,534,722	857	1,013	**Outside Adjustment 1**
2028	Reciprocating Engines (41 MW)	16.09	2,494,045	847	1,002	$0
2029		15.41	2,411,284	834	983	**Outside Adjustment 2**
2030		14.30	2,400,194	845	987	$0
2031	Reciprocating Engines (41 MW)	14.85	2,422,331	834	990	**Outside Model Adjustment 3**
2032	Aeroderivative (40 MW)	15.40	2,423,787	839	990	$0
2033	Aeroderivative (40 MW)	15.96	2,450,593	849	1,000	**Outside Model Adjustment 4**
2034		14.61	2,436,965	844	996	$0
2035	Aeroderivative (40 MW)	14.95	2,400,587	832	987	**Total Optimized NPV + Adjustments**
2036	Solar PV Large (50 MW)	14.66	2,451,766	843	984	$6,800,808,469
	Solar PV Distribution (50 MW)					**Average Risk NPV + Adjustments**
						$6,802,949,822

Table 37. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = LOW, GAS = MID, CO_2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$6,467,719,859
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,213,530	972	1,472	24.70
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,818,348	892	1,292	$6,468,229,668
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,535,775	824	1,138	$33,404,583
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,403,789	781	1,062	74,776,856
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	2,290,707	751	987	$0
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	25.24	2,597,212	846	1,015	868
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
2024		24.54	2,643,993	872	1,028	1082
2025		24.06	2,596,968	857	1,019	**20-Year Freshwater (Bn of Gal)**
2026		23.65	2,488,939	847	998	43.169
2027		23.02	2,538,154	856	1,013	**Outside Adjustment 1**
2028	Reciprocating Engines (41 MW)	16.09	2,497,512	847	1,002	$0
2029		15.41	2,414,931	833	983	**Outside Adjustment 2**
2030		14.30	2,404,045	844	986	$0
2031	Reciprocating Engines (41 MW)	14.85	2,425,504	834	990	**Outside Model Adjustment 3**
2032	Aeroderivative (40 MW)	15.40	2,426,354	838	990	$0
2033	Aeroderivative (40 MW)	15.96	2,453,038	848	1,000	**Outside Model Adjustment 4**
2034		14.61	2,439,904	844	995	$0
2035	Aeroderivative (40 MW)	14.95	2,403,389	832	987	**Total Optimized NPV + Adjustments**
2036	Solar PV Large (100 MW)	14.66	2,458,075	844	987	$6,467,719,859
						Average Risk NPV + Adjustments
						$6,468,229,668

Table 38. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = LOW, GAS = MID, CO_2 = $8 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,757,443	1,290	1,666	$6,896,169,109
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,163,723	958	1,446	24.92
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,804,507	886	1,281	$6,891,809,192
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,540,289	823	1,137	$93,000,510
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,405,630	781	1,062	74,617,194
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	2,291,879	751	987	$382,759,803
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	25.24	2,598,595	845	1,015	866
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
2024		24.54	2,645,569	871	1,027	1080
2025		24.06	2,598,409	857	1,018	**20-Year Freshwater (Bn of Gal)**
2026		23.65	2,489,490	847	998	43.050
2027		23.02	2,538,450	856	1,013	**Outside Adjustment 1**
2028	Reciprocating Engines (41 MW)	16.09	2,497,865	846	1,002	$0
2029		15.41	2,415,412	833	983	**Outside Adjustment 2**
2030		14.30	2,404,540	844	986	$0
2031	Reciprocating Engines (41 MW)	14.85	2,426,979	833	990	**Outside Model Adjustment 3**
2032	Aeroderivative (40 MW)	15.40	2,427,620	838	990	$0
2033	Aeroderivative (40 MW)	15.96	2,454,155	848	1,000	**Outside Model Adjustment 4**
2034		14.61	2,441,131	843	995	$0
2035	Aeroderivative (40 MW)	14.95	2,404,877	831	987	**Total Optimized NPV + Adjustments**
2036	Solar PV Large (100 MW)	14.66	2,459,267	844	987	$6,896,169,109
						Average Risk NPV + Adjustments
						$6,891,809,192

Table 39. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = LOW, GAS = MID, CO_2 = $20 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,515,537	1,234	1,580	$7,530,336,672
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	2,925,973	902	1,336	25.68
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,632,968	846	1,201	$7,507,917,843
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,438,735	797	1,088	$209,045,342
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,319,387	759	1,021	73,019,761
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	2,240,323	736	962	$932,570,746
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	25.24	2,532,639	826	985	848
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
2024		24.54	2,583,832	854	1,000	1049
2025		24.06	2,559,613	844	1,000	**20-Year Freshwater (Bn of Gal)**
2026		23.65	2,466,402	838	985	41.827
2027		23.02	2,506,985	845	997	**Outside Adjustment 1**
2028	Reciprocating Engines (41 MW)	16.09	2,477,543	838	990	$0
2029		15.41	2,383,515	822	967	**Outside Adjustment 2**
2030		14.30	2,376,310	834	972	$0
2031	Reciprocating Engines (41 MW)	14.85	2,404,442	825	978	**Outside Model Adjustment 3**
2032	Aeroderivative (40 MW)	15.40	2,411,145	831	981	$0
2033	Aeroderivative (40 MW)	15.96	2,418,342	837	983	**Outside Model Adjustment 4**
2034		14.61	2,423,548	836	986	$0
2035	Aeroderivative (40 MW)	14.95	2,381,933	823	974	**Total Optimized NPV + Adjustments**
2036	Solar PV Large (50 MW)	14.66	2,418,844	831	967	$7,530,336,672
	Solar PV Distribution (50 MW)					**Average Risk NPV + Adjustments**
						$7,507,917,843

Table 40. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = LOW, GAS = MID, CO_2 = $40 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,043,424	1,127	1,414	$8,531,905,469
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	2,549,248	815	1,164	26.56
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,317,093	773	1,057	$8,492,925,877
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,156,194	732	961	$401,793,360
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,074,898	703	912	67,495,085
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	2,032,733	690	872	$1,722,418,557
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	25.24	2,253,929	760	875	781
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
2024		24.54	2,315,254	789	895	932
2025		24.06	2,314,540	785	903	**20-Year Freshwater (Bn of Gal)**
2026		23.65	2,257,829	787	900	37.601
2027		23.02	2,279,806	789	905	**Outside Adjustment 1**
2028	Reciprocating Engines (41 MW)	16.09	2,266,783	787	904	$0
2029		15.41	2,190,690	774	887	**Outside Adjustment 2**
2030		14.30	2,166,038	782	884	$0
2031	Reciprocating Engines (41 MW)	14.85	2,190,249	772	889	**Outside Model Adjustment 3**
2032	Solar PV Distribution (50 MW)	14.25	2,182,458	767	869	
2033	Aeroderivative (40 MW)	14.82	2,166,508	767	864	**Outside Model Adjustment 4**
2034	Aeroderivative (40 MW)	15.49	2,176,365	768	867	$0
2035	Wind (100 MW)	14.09	2,010,925	707	774	**Total Optimized NPV + Adjustments**
2036	Aeroderivative (40 MW)	14.05	2,081,819	742	816	$8,531,905,469
						Average Risk NPV + Adjustments
						$8,492,925,877

Table 41. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = MID, GAS = LOW, CO_2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,822,171,344
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,383,234	986	1,476	29.68
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,127,484	919	1,312	$6,814,259,211
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,883,798	854	1,169	$44,844,728
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,850,014	825	1,115	92,875,548
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,817,420	800	1,049	$28,513,140
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,404,614	916	1,100	944
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1163
2024		18.27	3,561,552	953	1,128	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,452,248	924	1,096	52.014
2026		15.97	3,476,559	934	1,106	**Outside Adjustment 1**
2027		14.72	3,668,644	962	1,144	$0
2028	Large GT (187 MW)	14.81	3,604,438	949	1,130	**Outside Adjustment 2**
2029	Solar PV Large (50 MW)	14.28	3,495,787	918	1,081	$0
2030	Reciprocating Engines (41 MW)	14.46	3,579,552	937	1,094	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,660,129	934	1,105	$0
2032	Large GT (187 MW)	20.37	3,704,806	941	1,109	**Outside Model Adjustment 4**
2033		18.34	3,857,057	959	1,125	$0
2034		16.46	3,836,322	951	1,117	**Total Optimized NPV + Adjustments**
2035		14.39	3,936,281	954	1,125	$6,822,171,344
2036	Aeroderivative (40 MW)	14.40	4,111,888	984	1,154	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$6,814,259,211

Table 42. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = MID, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,146,517,313
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,143,415,687
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,473,482
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,663
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,839,696
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,146,517,313
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,143,415,687

Table 43. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = MID, GAS = HIGH, CO_2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,360	1,302	1,682	$7,469,083,531
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,375,457	988	1,478	30.94
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,111,376	923	1,315	$7,468,340,030
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,865,593	858	1,171	$127,289,631
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,830,211	829	1,117	90,463,988
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,810,643	806	1,054	$319,116,099
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,424,871	933	1,119	915
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1108
2024		18.27	3,548,525	964	1,137	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,522,625	953	1,132	51.029
2026		15.97	3,488,772	952	1,124	**Outside Adjustment 1**
2027		14.72	3,636,883	970	1,147	$0
2028	Large GT (187 MW)	14.81	3,580,231	958	1,135	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,492,482	931	1,093	$0
2030	Solar PV Large (100 MW)	14.20	3,385,757	908	1,039	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.20	3,214,313	846	959	$0
	Wind (100 MW)					**Outside Model Adjustment 4**
2032	Large GT (187 MW)	20.32	3,265,991	854	966	$0
2033		18.30	3,386,216	871	984	**Total Optimized NPV + Adjustments**
2034		16.42	3,399,884	869	982	$7,469,083,531
2035	Wind (100 MW)	14.55	3,206,532	813	904	**Average Risk NPV + Adjustments**
2036	Reciprocating Engines (41 MW)	14.60	3,371,804	843	935	$7,468,340,030
	Solar PV Large (50 MW)					

Table 44. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = MID, GAS = MID, CO_2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,946,189,906
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.57
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$6,944,021,923
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$71,922,296
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,713,633
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,814,581	805	1,054	$0
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,431,983	932	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,556,424	962	1,137	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,339	951	1,131	52.657
2026		15.97	3,497,044	950	1,123	**Outside Adjustment 1**
2027		14.72	3,644,981	968	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,361	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,498,859	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,572,996	947	1,103	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,631,545	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,080	949	1,115	**Outside Model Adjustment 4**
2033		18.34	3,839,582	968	1,131	$0
2034		16.46	3,825,810	962	1,126	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,269	962	1,129	$6,946,189,906
2036	Aeroderivative (40 MW)	14.40	4,074,980	990	1,156	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$6,944,021,923

Table 45. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = MID, GAS = MID, CO_2 = $8 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,788,877	1,292	1,666	$7,465,410,969
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,328,996	973	1,451	32.18
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,098,557	913	1,301	$7,456,872,246
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,873,924	856	1,170	$122,329,346
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,837,603	827	1,116	93,300,529
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,999	805	1,054	$462,475,297
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,435,707	931	1,118	948
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1164
2024		18.27	3,560,379	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,533,607	950	1,131	52.413
2026		15.97	3,498,889	949	1,123	**Outside Adjustment 1**
2027		14.72	3,646,732	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,769	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,776	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,614	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,635,167	939	1,107	$0
2032	Large GT (187 MW)	20.37	3,692,348	948	1,114	**Outside Model Adjustment 4**
2033		18.34	3,842,497	967	1,131	$0
2034		16.46	3,827,562	960	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,912,911	960	1,128	$7,465,410,969
2036	Solar PV Large (50 MW)	14.20	3,883,336	948	1,094	**Average Risk NPV + Adjustments**
	Solar PV Large (100 MW)					$7,456,872,246

Table 46. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = MID, GAS = MID, CO_2 = $20 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,544,650	1,235	1,579	$8,228,244,547
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,076,490	915	1,339	30.64
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	2,907,933	870	1,219	$8,194,766,799
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,757,481	827	1,119	$242,030,982
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,733,095	802	1,071	88,222,767
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,737,888	786	1,021	$1,100,800,862
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,319,280	901	1,075	893
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1077
2024		18.27	3,465,871	938	1,102	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,455,528	930	1,102	49.263
2026		15.97	3,439,614	932	1,100	**Outside Adjustment 1**
2027		14.72	3,592,052	951	1,125	$0
2028	Large GT (187 MW)	14.81	3,543,930	942	1,116	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,443,551	913	1,070	$0
2030	Solar PV Large (100 MW)	14.20	3,354,687	892	1,021	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.20	3,181,625	832	944	$0
	Wind (100 MW)					**Outside Model Adjustment 4**
2032	Large GT (187 MW)	20.32	3,235,727	842	952	$0
2033		18.30	3,348,713	857	967	**Total Optimized NPV + Adjustments**
2034		16.42	3,369,031	856	968	$8,228,244,547
2035		14.35	3,412,811	852	968	**Average Risk NPV + Adjustments**
2036	Reciprocating Engines (41 MW)	14.60	3,335,228	829	919	$8,194,766,799
	Solar PV Large (50 MW)					
	Wind (100 MW)					

Table 47. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = MID, GAS = MID, CO_2 = $40 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,067,887	1,127	1,413	$9,373,826,219
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	2,682,915	826	1,168	23.63
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	2,541,817	790	1,065	$9,321,873,354
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,430,115	756	984	$435,211,503
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,435,268	737	952	76,252,396
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,483,696	732	925	$1,915,872,908
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.99	2,716,930	771	870	763
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					870
	Wind (100 MW)					**20-Year Freshwater (Bn of Gal)**
2024	Wind (100 MW)	18.75	2,643,915	755	820	41.366
2025		17.55	2,677,203	754	830	**Outside Adjustment 1**
2026		16.44	2,670,384	760	831	$0
2027		15.18	2,753,992	767	844	**Outside Adjustment 2**
2028	Large GT (187 MW)	15.27	2,762,379	767	845	$0
2029	Solar PV Distribution (50 MW)	14.74	2,682,357	744	812	**Outside Model Adjustment 3**
2030	Solar PV Large (100 MW)	14.64	2,619,878	728	774	$0
2031	Solar PV Large (100 MW)	14.15	2,605,977	698	742	**Outside Model Adjustment 4**
2032	Large GT (187 MW)	20.28	2,667,763	710	753	$0
2033		18.26	2,730,866	719	762	**Total Optimized NPV + Adjustments**
2034		16.38	2,761,899	720	765	$9,373,826,219
2035		14.31	2,786,102	715	765	**Average Risk NPV + Adjustments**
2036	Reciprocating Engines (82 MW)	15.31	2,956,894	751	806	$9,321,873,354

Table 48. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = HIGH, GAS = LOW, CO_2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,431,760,922
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,432,369	985	1,464	23.49
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,120,682	901	1,264	$7,420,233,624
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$74,992,256
2020	Data Center1 Solar3 (30 MW)	14.25	2,959,011	838	1,119	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					109,903,731
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$35,092,028
2021	Data Center1 Solar4 (30 MW)	19.77	3,139,995	831	1,094	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					972
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	3,330,147	832	1,068	1161
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Data Center1 Solar6 (20 MW)	17.82	4,047,735	933	1,093	58.769
	Large GT (187 MW)					**Outside Adjustment 1**
	Palo Verde Undepreciated Assets					$0
2024		14.44	4,387,894	975	1,125	**Outside Adjustment 2**
2025	Large GT (187 MW)	20.05	4,378,465	955	1,103	$0
2026		18.46	4,445,043	965	1,112	**Outside Model Adjustment 3**
2027		16.76	4,662,534	988	1,140	$0
2028	Large GT (187 MW)	16.25	4,659,065	982	1,134	**Outside Model Adjustment 4**
2029		14.53	4,671,480	972	1,119	$0
2030	Reciprocating Engines (41 MW)	14.13	4,777,903	984	1,122	**Total Optimized NPV + Adjustments**
2031	Large GT (187 MW)	18.91	4,907,741	985	1,134	$7,431,760,922
2032		16.65	5,002,732	994	1,140	**Average Risk NPV + Adjustments**
2033		14.46	5,160,942	1,003	1,143	$7,420,233,624
2034	Aeroderivatives (80 MW)	15.20	5,202,705	999	1,142	
2035	Aeroderivative (40 MW)	14.32	5,330,895	1,000	1,142	
2036	Rio Bravo CC Expansion (210 MW)	14.29	5,488,282	1,013	1,149	

Table 49. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = HIGH, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,967,321,313
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,428,305	986	1,465	23.09
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,110,649	903	1,266	$7,962,572,037
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$148,465,950
2020	Data Center1 Solar3 (30 MW)	14.25	2,942,983	842	1,120	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					108,407,537
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$211,601,519
2021	Data Center1 Solar4 (30 MW)	19.77	3,122,953	835	1,096	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					959
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	3,325,470	839	1,074	1135
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Data Center1 Solar6 (20 MW)	17.82	4,076,979	950	1,112	58.657
	Large GT (187 MW)					**Outside Adjustment 1**
	Palo Verde Undepreciated Assets					$0
2024		14.44	4,373,806	985	1,133	**Outside Adjustment 2**
2025	Large GT (187 MW)	20.05	4,455,920	982	1,135	$0
2026		18.46	4,467,746	983	1,130	**Outside Model Adjustment 3**
2027		16.76	4,629,631	995	1,142	$0
2028	Large GT (187 MW)	16.25	4,637,565	990	1,139	**Outside Model Adjustment 4**
2029		14.53	4,667,982	984	1,129	$0
2030	Reciprocating Engines (41 MW)	14.13	4,764,487	995	1,130	**Total Optimized NPV + Adjustments**
2031	Large GT (187 MW)	18.91	4,884,713	995	1,140	$7,967,321,313
2032	Wind (100 MW)	16.84	4,742,597	962	1,090	**Average Risk NPV + Adjustments**
2033	Wind (100 MW)	14.82	4,653,196	931	1,038	$7,962,572,037
2034	Aeroderivative (40 MW)	14.14	4,696,945	931	1,039	
2035	Aeroderivative (40 MW)	14.49	4,635,166	900	999	
	Solar PV Large (100 MW)					
2036	Rio Bravo CC Expansion (210 MW)	14.46	4,844,047	925	1,022	

Table 50. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = HIGH, GAS = HIGH, CO_2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,207	1,304	1,682	$8,431,056,625
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,424,113	987	1,466	20.89
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,105,327	904	1,267	$8,430,176,858
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$159,936,993
2020	Data Center1 Solar3 (30 MW)	14.25	2,939,049	842	1,121	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					96,437,922
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$343,661,755
2021	Data Center1 Solar4 (30 MW)	19.77	3,115,323	837	1,096	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					849
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	3,318,560	841	1,075	969
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Data Center1 Solar6 (20 MW)	14.24	3,538,160	848	958	53.643
	Palo Verde Undepreciated Assets					**Outside Adjustment 1**
	PVNGS U1 Lease Purchase (104 MW)					$0
2024	Large GT (187 MW)	18.81	3,764,589	874	969	**Outside Adjustment 2**
2025		16.63	3,904,756	883	990	$0
2026	Wind (100 MW)	15.29	3,670,069	839	920	**Outside Model Adjustment 3**
2027	Solar PV Large (50 MW)	14.33	3,678,486	823	897	$0
2028	Large GT (187 MW)	14.07	3,498,766	782	841	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2029	Large GT (187 MW)	19.63	3,551,827	786	846	**Total Optimized NPV + Adjustments**
2030		17.59	3,585,227	791	841	$8,431,056,625
2031		15.30	3,747,652	799	865	**Average Risk NPV + Adjustments**
2032	Solar PV Large (100 MW)	14.40	3,721,359	784	838	$8,430,176,858
2033	Large GT (187 MW)	18.99	3,807,904	788	839	
2034		16.81	3,906,207	798	853	
2035		14.51	4,041,847	804	866	
2036	Aeroderivative (40 MW)	14.79	4,257,782	833	895	
	Reciprocating Engines (41 MW)					

Table 51. 17 IRP: SJGS Continues Beyond 2022 (LOAD = HIGH, GAS = MID, CO_2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,725,801,906
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,428,305	986	1,465	23.45
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,110,649	903	1,266	$7,721,569,541
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$138,506,487
2020	Data Center1 Solar3 (30 MW)	14.25	2,942,983	842	1,120	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					109,000,382
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$0
2021	Data Center1 Solar4 (30 MW)	19.77	3,122,953	835	1,096	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					964
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	3,324,670	839	1,074	1142
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Data Center1 Solar6 (20 MW)	17.82	4,074,581	950	1,112	58.869
	Large GT (187 MW)					**Outside Adjustment 1**
	Palo Verde Undepreciated Assets					$0
2024		14.44	4,371,334	986	1,133	**Outside Adjustment 2**
2025	Large GT (187 MW)	20.05	4,454,696	982	1,135	$0
2026		18.46	4,467,107	983	1,130	**Outside Model Adjustment 3**
2027		16.76	4,626,860	995	1,143	$0
2028	Large GT (187 MW)	16.25	4,636,566	991	1,140	**Outside Model Adjustment 4**
2029		14.53	4,666,077	985	1,130	$0
2030	Reciprocating Engines (41 MW)	14.13	4,761,140	997	1,131	**Total Optimized NPV + Adjustments**
2031	Large GT (187 MW)	18.91	4,882,430	996	1,141	$7,725,801,906
2032		16.65	4,995,665	1,007	1,151	**Average Risk NPV + Adjustments**
2033	Wind (100 MW)	14.64	4,897,444	974	1,095	$7,721,569,541
2034	Aeroderivative (40 MW)	14.14	4,698,894	932	1,040	
	Wind (100 MW)					
2035	Aeroderivative (40 MW)	14.49	4,637,443	901	1,000	
	Solar PV Large (100 MW)					
2036	Rio Bravo CC Expansion (210 MW)	14.46	4,838,531	926	1,022	

Table 52. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = HIGH, GAS = MID, CO_2 = \$8 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,827,045	1,294	1,666	$8,315,786,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,377,517	972	1,439	22.30
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,093,057	896	1,254	$8,305,444,101
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$176,389,715
2020	Data Center1 Solar3 (30 MW)	14.25	2,949,389	840	1,120	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					106,472,706
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$520,090,844
2021	Data Center1 Solar4 (30 MW)	19.77	3,125,407	835	1,095	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					941
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	3,327,698	839	1,074	1110
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Data Center1 Solar6 (20 MW)	17.82	4,079,163	949	1,111	57.730
	Large GT (187 MW)					**Outside Adjustment 1**
	Palo Verde Undepreciated Assets					$0
2024		14.44	4,377,052	985	1,132	**Outside Adjustment 2**
2025	Large GT (187 MW)	20.05	4,459,630	981	1,135	$0
2026		18.46	4,470,867	982	1,129	**Outside Model Adjustment 3**
2027		16.76	4,629,822	995	1,142	$0
2028	Large GT (187 MW)	16.25	4,637,877	990	1,139	**Outside Model Adjustment 4**
2029		14.53	4,668,347	984	1,129	$0
2030	Solar PV Large (100 MW)	14.10	4,341,095	921	1,026	**Total Optimized NPV + Adjustments**
	Wind (100 MW)					$8,315,786,594
2031	Large GT (187 MW)	18.87	4,452,969	919	1,035	**Average Risk NPV + Adjustments**
2032		16.62	4,561,449	930	1,045	$8,305,444,101
2033	Wind (100 MW)	14.61	4,482,408	901	996	
2034	Reciprocating Engines (41 MW)	14.58	4,418,534	882	972	
	Solar PV Large (50 MW)					
2035	Aeroderivatives (80 MW)	15.10	4,538,822	883	976	
2036	Rio Bravo CC Expansion (210 MW)	15.06	4,759,103	910	1,002	

Table 53. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = HIGH, GAS = MID, CO_2 = $20 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,580,356	1,237	1,579	$9,165,350,906
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,146,485	919	1,339	19.32
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	2,919,986	857	1,182	$9,129,204,277
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$279,333,155
2020	Data Center1 Solar3 (30 MW)	14.25	2,822,039	810	1,067	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					99,251,186
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$1,212,175,288
2021	Data Center1 Solar4 (30 MW)	19.77	2,998,535	806	1,047	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					875
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	3,216,729	813	1,034	1014
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Data Center1 Solar6 (20 MW)	17.82	3,956,892	921	1,073	53.867
	Large GT (187 MW)					**Outside Adjustment 1**
	Palo Verde Undepreciated Assets					$0
2024	Wind (100 MW)	14.65	4,028,052	915	1,035	**Outside Adjustment 2**
2025	Solar PV Large (100 MW)	14.20	3,690,926	832	922	$0
	Wind (100 MW)					**Outside Model Adjustment 3**
2026	Large GT (187 MW)	20.29	3,706,958	836	922	$0
2027		18.56	3,885,916	854	945	**Outside Model Adjustment 4**
2028	Large GT (187 MW)	18.03	3,902,708	851	942	$0
2029		16.28	3,918,114	846	936	**Total Optimized NPV + Adjustments**
2030		14.29	4,041,769	865	949	$9,165,350,906
2031	Reciprocating Engines (41 MW)	14.25	4,051,094	845	933	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$9,129,204,277
2032	Large GT (187 MW)	18.95	4,153,699	856	944	
2033		16.72	4,333,554	873	959	
2034		14.58	4,372,747	872	959	
2035	Aeroderivatives (80 MW)	15.10	4,484,676	872	962	
2036	Rio Bravo CC Expansion (210 MW)	15.06	4,717,541	900	990	

Table 54. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = HIGH, GAS = MID, CO_2 = $40 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,098,453	1,128	1,413	$10,400,759,000
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	2,742,724	829	1,167	19.86
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	2,553,399	778	1,033	$10,341,291,297
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$461,943,287
2020	Data Center1 Solar3 (30 MW)	14.25	2,476,653	738	935	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					84,203,344
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$2,075,756,067
2021	Data Center1 Solar4 (30 MW)	19.77	2,661,177	737	927	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					738
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,869,261	746	920	813
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Data Center1 Solar6 (20 MW)	14.46	2,852,275	707	758	44.929
	Palo Verde Undepreciated Assets					**Outside Adjustment 1**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Wind (100 MW)					**Outside Adjustment 2**
2024	Large GT (187 MW)	19.65	2,847,651	689	713	$0
	PVNGS U2 Lease Purchase (10 MW)					**Outside Model Adjustment 3**
	Wind (100 MW)					$0
2025		17.46	2,983,162	701	736	**Outside Model Adjustment 4**
2026		15.90	3,039,540	712	748	$0
2027		14.23	3,119,839	714	751	**Total Optimized NPV + Adjustments**
2028	Large GT (187 MW)	14.46	3,123,442	708	743	$10,400,759,000
	Solar PV Large (50 MW)					**Average Risk NPV + Adjustments**
2029	Solar PV Large (100 MW)	14.12	3,048,413	684	711	$10,341,291,297
2030	Large GT (187 MW)	19.30	3,090,921	691	710	
2031		16.98	3,215,848	696	728	
2032		14.76	3,345,254	713	746	
2033	Reciprocating Engines (41 MW)	14.09	3,422,345	716	747	
2034	Large GT (187 MW)	18.61	3,502,680	724	758	
2035		16.28	3,632,845	729	771	
2036	Aeroderivative (40 MW)	15.12	3,841,276	758	800	

APPENDIX M. TOP RANKED PORTFOLIOS FOR EACH OF 21 SJGS RETIRES SCENARIOS

Table 55. 2017 IRP: SJGS Retires in 2022 (LOAD = LOW, GAS = LOW, CO_2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$5,803,282,750
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,256,735	978	1,482	9.39
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,786,239	883	1,278	$5,796,418,336
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,598,976	829	1,150	$66,225,810
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,505,585	793	1,085	54,215,922
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,940,595	679	855	$13,670,602
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	18.50	1,148,102	527	470	646
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					694
2024		17.81	1,165,853	546	475	**20-Year Freshwater (Bn of Gal)**
2025		17.35	1,108,325	528	461	26.914
2026		16.98	1,053,983	529	448	**Outside Adjustment 1**
2027		16.38	1,081,345	529	456	$0
2028	Large GT (187 MW)	17.32	1,007,480	520	436	**Outside Adjustment 2**
2029		16.64	1,002,323	517	435	$0
2030		15.52	1,002,586	528	436	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	16.05	986,628	510	431	$0
2032		14.53	956,938	512	422	**Outside Model Adjustment 4**
2033	Reciprocating Engines (41 MW)	15.15	996,398	518	432	$0
2034	Aeroderivative (40 MW)	15.81	959,577	514	423	**Total Optimized NPV + Adjustments**
2035		14.16	979,550	508	428	$5,803,282,750
2036	Aeroderivative (40 MW)	14.13	1,082,104	545	472	**Average Risk NPV + Adjustments**
						$5,796,418,336

Table 56. 2017 IRP: SJGS Retires in 2022 (LOAD = LOW, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$6,184,130,719
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,253,464	979	1,483	8.53
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,778,060	885	1,280	$6,177,892,527
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,587,131	832	1,152	$132,243,170
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,495,425	795	1,086	53,652,788
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,926,309	685	857	$80,267,478
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	18.50	1,100,014	539	460	637
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					658
2024		17.81	1,118,420	558	466	**20-Year Freshwater (Bn of Gal)**
2025		17.35	1,053,490	542	449	27.108
2026		16.98	997,393	542	435	**Outside Adjustment 1**
2027		16.38	1,034,695	541	446	$0
2028	Large GT (187 MW)	17.32	959,734	532	425	**Outside Adjustment 2**
2029		16.64	954,734	529	424	$0
2030		15.52	955,674	540	425	**Outside Model Adjustment 3**
2031	Wind (100 MW)	14.18	783,728	479	345	$0
2032	Reciprocating Engines (41 MW)	14.79	747,746	479	333	**Outside Model Adjustment 4**
2033	Solar PV Distribution (50 MW)	14.21	737,941	470	320	$0
2034	Reciprocating Engines (41 MW)	14.94	707,395	467	310	**Total Optimized NPV + Adjustments**
2035	Solar PV Large (50 MW)	14.16	677,868	446	293	$6,184,130,719
2036	Aeroderivative (40 MW)	14.13	765,833	480	332	**Average Risk NPV + Adjustments**
						$6,177,892,527

Table 57. 2017 IRP: SJGS Retires in 2022 (LOAD = LOW, GAS = HIGH, CO_2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,212	1,301	1,682	$6,488,710,063
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,249,282	980	1,484	7.84
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,772,693	887	1,280	$6,489,712,844
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,584,543	833	1,152	$114,965,662
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,492,456	796	1,086	47,662,900
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,917,470	687	856	$123,893,207
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.22	590,429	410	239	555
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					511
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Wind (100 MW)					25.806
2024	Reciprocating Engines (41 MW)	15.78	559,449	413	223	**Outside Adjustment 1**
2025		15.34	543,671	408	222	$0
2026		14.97	516,863	413	215	**Outside Adjustment 2**
2027		14.38	498,831	397	205	$0
2028	Large GT (187 MW)	15.34	481,782	401	202	**Outside Model Adjustment 3**
2029		14.67	484,199	401	205	$0
2030	Reciprocating Engines (41 MW)	15.73	449,126	399	188	**Outside Model Adjustment 4**
2031		14.13	464,759	391	197	$0
2032	Aeroderivative (40 MW)	14.68	461,072	399	197	**Total Optimized NPV + Adjustments**
2033	Solar PV Distribution (50 MW)	14.11	422,427	380	174	$6,488,710,063
2034	Aeroderivative (40 MW)	14.79	420,529	387	176	**Average Risk NPV + Adjustments**
2035	Solar PV Large (50 MW)	14.02	417,782	372	171	$6,489,712,844
2036	Aeroderivative (40 MW)	14.22	358,808	357	142	
	Wind (100 MW)					

Table 58. 2017 IRP: SJGS Retires in 2022 (LOAD = LOW, GAS = MID, CO_2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$6,092,810,438
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,253,464	979	1,483	8.91
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,778,060	885	1,280	$6,086,474,054
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,587,131	832	1,152	$129,284,208
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,495,425	795	1,086	53,924,848
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,926,104	685	857	$0
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	18.50	1,095,004	540	459	641
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					663
2024		17.81	1,112,551	559	465	**20-Year Freshwater (Bn of Gal)**
2025		17.35	1,050,661	543	448	27.209
2026		16.98	996,466	542	435	**Outside Adjustment 1**
2027		16.38	1,029,707	542	444	$0
2028	Large GT (187 MW)	17.32	955,313	534	424	**Outside Adjustment 2**
2029		16.64	950,257	530	423	$0
2030		15.52	951,628	542	425	**Outside Model Adjustment 3**
2031	Wind (100 MW)	14.18	780,349	480	345	$0
2032	Reciprocating Engines (41 MW)	14.79	745,637	480	333	**Outside Model Adjustment 4**
2033	Reciprocating Engines (41 MW)	15.40	779,484	486	342	$0
2034		14.06	750,385	484	334	**Total Optimized NPV + Adjustments**
2035	Aeroderivative (40 MW)	14.41	763,094	477	338	$6,092,810,438
2036	Solar PV Large (50 MW)	14.13	763,559	482	332	**Average Risk NPV + Adjustments**
	Solar PV Distribution (50 MW)					$6,086,474,054

Table 59. 2017 IRP: SJGS Retires in 2022 (LOAD = LOW, GAS = MID, CO_2 = $8 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,757,443	1,290	1,666	$6,421,886,969
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,202,872	965	1,456	8.57
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,759,240	878	1,266	$6,412,339,241
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,591,644	831	1,151	$153,855,861
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,497,264	795	1,086	53,270,726
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,928,655	685	857	$294,758,834
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	18.50	1,104,195	537	460	632
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					652
2024		17.81	1,122,632	557	467	**20-Year Freshwater (Bn of Gal)**
2025		17.35	1,060,853	540	450	26.917
2026		16.98	1,002,709	541	436	**Outside Adjustment 1**
2027		16.38	1,035,463	541	446	$0
2028	Large GT (187 MW)	17.32	960,261	532	425	**Outside Adjustment 2**
2029		16.64	955,521	528	424	$0
2030	Wind (100 MW)	15.78	789,400	493	347	**Outside Model Adjustment 3**
2031		14.18	787,946	478	347	$0
2032	Reciprocating Engines (41 MW)	14.79	751,973	478	334	**Outside Model Adjustment 4**
2033	Solar PV Distribution (50 MW)	14.21	741,424	469	321	$0
2034	Reciprocating Engines (41 MW)	14.94	711,378	466	311	**Total Optimized NPV + Adjustments**
2035	Solar PV Large (50 MW)	14.16	682,191	445	294	$6,421,886,969
2036	Aeroderivative (40 MW)	14.13	769,116	479	333	**Average Risk NPV + Adjustments**
						$6,412,339,241

Table 60. 2017 IRP: SJGS Retires in 2022 (LOAD = LOW, GAS = MID, CO_2 = $20 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,515,537	1,234	1,580	$6,898,057,516
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	2,985,659	914	1,356	7.44
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,579,168	835	1,183	$6,881,643,369
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,495,181	806	1,105	$208,909,999
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,420,570	775	1,049	49,778,306
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,906,660	674	842	$692,965,379
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	18.77	944,467	486	387	587
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					580
	Wind (100 MW)					**20-Year Freshwater (Bn of Gal)**
2024		18.08	954,761	505	391	25.409
2025		17.63	901,348	490	376	**Outside Adjustment 1**
2026		17.25	849,542	490	363	$0
2027		16.65	875,958	488	370	**Outside Adjustment 2**
2028	Large GT (187 MW)	17.59	815,268	482	352	$0
2029		16.90	805,080	477	350	**Outside Model Adjustment 3**
2030	Wind (100 MW)	16.04	658,970	445	281	$0
2031		14.44	657,238	432	281	**Outside Model Adjustment 4**
2032	Reciprocating Engines (41 MW)	15.04	625,092	432	270	$0
2033	Solar PV Distribution (50 MW)	14.46	616,479	423	259	**Total Optimized NPV + Adjustments**
2034	Solar PV Large (50 MW)	14.01	567,421	412	237	$6,898,057,516
2035	Reciprocating Engines (41 MW)	14.41	568,771	402	237	**Average Risk NPV + Adjustments**
2036	Aeroderivative (40 MW)	14.37	647,489	434	272	$6,881,643,369

Table 61. 2017 IRP: SJGS Retires in 2022 (LOAD = LOW, GAS = MID, CO_2 = $40 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,043,424	1,127	1,414	$7,630,563,813
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	2,609,954	827	1,185	7.46
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,261,336	762	1,036	$7,614,744,445
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,213,053	742	979	$341,245,007
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,180,205	721	944	46,570,815
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,734,275	634	764	$1,287,887,611
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	18.77	964,114	482	392	547
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					519
	Wind (100 MW)					**20-Year Freshwater (Bn of Gal)**
2024	Wind (100 MW)	18.36	812,886	456	325	23.388
2025		17.90	770,118	442	313	**Outside Adjustment 1**
2026		17.52	721,222	442	299	$0
2027		16.92	741,346	439	305	**Outside Adjustment 2**
2028	Large GT (187 MW)	17.86	695,425	434	291	$0
2029		17.17	680,232	429	287	**Outside Model Adjustment 3**
2030		16.04	679,851	440	287	$0
2031		14.44	678,009	426	287	**Outside Model Adjustment 4**
2032	Reciprocating Engines (41 MW)	15.04	646,159	427	276	$0
2033	Solar PV Distribution (50 MW)	14.46	636,789	418	265	**Total Optimized NPV + Adjustments**
2034	Solar PV Large (50 MW)	14.01	586,707	407	243	$7,630,563,813
2035	Reciprocating Engines (41 MW)	14.41	588,159	398	243	**Average Risk NPV + Adjustments**
2036	Solar PV Large (100 MW)	14.13	609,758	407	245	$7,614,744,445

Table 62. 2017 IRP: SJGS Retires in 2022 (LOAD = MID, GAS = LOW, CO_2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,369,241,156
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,422,782	993	1,487	17.02
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,086,454	912	1,299	$6,365,591,056
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,928,001	861	1,182	$113,134,043
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,928,592	837	1,136	68,149,922
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,429,765	727	917	$18,690,673
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Aeroderivatives (80 MW)	14.07	1,665,784	573	549	696
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					759
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					30.351
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
2024	Large GT (187 MW)	21.67	1,737,030	596	563	$0
2025		20.42	1,725,015	583	559	**Outside Adjustment 2**
2026		19.28	1,727,429	590	560	$0
2027		17.98	1,793,958	598	572	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	18.03	1,754,635	592	563	$0
2029		16.67	1,806,061	594	571	**Outside Model Adjustment 4**
2030		14.97	1,867,034	610	582	$0
2031	Large GT (187 MW)	21.19	1,906,992	602	588	**Total Optimized NPV + Adjustments**
2032		19.11	1,924,025	607	588	$6,369,241,156
2033		17.10	2,040,410	623	607	**Average Risk NPV + Adjustments**
2034		15.22	2,045,152	620	607	$6,365,591,056
2035	Aeroderivative (40 MW)	14.81	2,127,422	623	618	
2036	Solar PV Large (50 MW)	14.62	2,093,190	619	598	
	Solar PV Large (100 MW)					

Table 63. 2017 IRP: SJGS Retires in 2022 (LOAD = MID, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,982,684,359
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	16.55
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,992,040,928
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$184,746,914
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	61,884,891
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$97,203,172
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Aeroderivatives (80 MW)	14.07	1,619,630	583	543	629
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					638
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					29.402
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
2024	Solar PV Large (100 MW)	14.33	1,556,513	576	511	$0
2025	Solar PV Large (50 MW)	14.24	1,290,574	511	421	**Outside Adjustment 2**
	Wind (100 MW)					$0
2026	Aeroderivative (40 MW)	15.05	1,287,469	517	420	**Outside Model Adjustment 3**
2027	Wind (100 MW)	14.03	1,183,638	480	376	$0
2028	Large GT (187 MW)	14.14	1,162,792	479	370	**Outside Model Adjustment 4**
2029	Large GT (187 MW)	21.34	1,195,492	480	377	$0
2030		19.58	1,245,235	495	388	**Total Optimized NPV + Adjustments**
2031		17.46	1,284,033	488	396	$6,982,684,359
2032		15.44	1,297,019	494	397	**Average Risk NPV + Adjustments**
2033	Solar PV Large (50 MW)	14.24	1,344,569	494	399	$6,992,040,928
2034	Large GT (187 MW)	20.26	1,350,810	497	400	
2035		18.12	1,418,254	497	413	
2036		15.73	1,581,959	532	454	

Table 64. 2017 IRP: SJGS Retires in 2022 (LOAD = MID, GAS = HIGH, CO2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,360	1,302	1,682	$7,378,949,828
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,415,016	995	1,489	16.41
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,069,838	915	1,301	$7,396,797,795
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,910,535	865	1,183	$197,969,570
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,910,054	841	1,137	55,532,008
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,409,932	738	922	$153,953,272
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.05	916,275	430	298	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					520
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Solar PV Large (50 MW)					28.197
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
	Solar PV Large (100 MW)					$0
	Wind (100 MW)					**Outside Adjustment 2**
2024	Reciprocating Engines (41 MW)	14.84	772,848	400	242	$0
	Wind (100 MW)					**Outside Model Adjustment 3**
2025	Reciprocating Engines (41 MW)	15.62	779,562	398	246	$0
2026		14.53	795,286	408	251	**Outside Model Adjustment 4**
2027	Solar PV Large (50 MW)	14.10	774,345	389	237	$0
2028	Large GT (187 MW)	14.21	784,838	396	242	**Total Optimized NPV + Adjustments**
2029	Large GT (187 MW)	21.41	828,324	401	254	$7,378,949,828
2030		19.65	830,029	405	251	**Average Risk NPV + Adjustments**
2031		17.52	886,831	404	266	$7,396,797,795
2032		15.51	918,281	414	274	
2033	Aeroderivative (40 MW)	15.26	953,595	415	278	
2034	Aeroderivative (40 MW)	15.10	984,542	424	287	
2035	Aeroderivative (40 MW)	14.69	1,063,922	428	306	
2036	Rio Bravo CC Expansion (210 MW)	15.29	1,089,673	437	309	

Table 65. 2017 IRP: SJGS Retires in 2022 (LOAD = MID, GAS = MID, CO_2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,873,440,516
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	16.60
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,880,952,891
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$199,112,232
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	62,309,380
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,417,507	736	922	$0
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Aeroderivatives (80 MW)	14.07	1,614,968	584	542	634
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					643
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					29.501
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
2024	Solar PV Large (100 MW)	14.33	1,550,900	578	510	$0
2025	Aeroderivative (40 MW)	15.07	1,530,798	567	505	**Outside Adjustment 2**
2026	Wind (100 MW)	14.22	1,342,005	531	441	$0
2027	Solar PV Large (50 MW)	14.03	1,178,917	481	375	**Outside Model Adjustment 3**
	Wind (100 MW)					$0
2028	Large GT (187 MW)	14.14	1,159,014	480	369	**Outside Model Adjustment 4**
2029	Large GT (187 MW)	21.34	1,191,665	481	377	$0
2030		19.58	1,241,906	496	388	**Total Optimized NPV + Adjustments**
2031		17.46	1,280,192	490	395	$6,873,440,516
2032		15.44	1,295,579	496	397	**Average Risk NPV + Adjustments**
2033	Solar PV Large (50 MW)	14.24	1,343,979	496	400	$6,880,952,891
2034	Large GT (187 MW)	20.26	1,350,469	499	401	
2035		18.12	1,420,134	499	414	
2036		15.73	1,584,760	535	456	

Table 66. 2017 IRP: SJGS Retires in 2022 (LOAD = MID, GAS = MID, CO_2 = $8 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,788,877	1,292	1,666	$7,240,964,781
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,366,586	979	1,462	16.43
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,055,264	905	1,286	$7,247,436,170
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,918,469	863	1,183	$203,626,615
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,915,926	840	1,137	61,138,580
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,419,326	736	922	$329,374,316
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Aeroderivative (40 MW)	14.07	1,301,320	511	432	622
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					627
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					29.139
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
	Solar PV Large (100 MW)					$0
	Wind (100 MW)					**Outside Adjustment 2**
2024	Aeroderivative (40 MW)	14.57	1,366,472	532	446	$0
2025	Solar PV Large (50 MW)	14.24	1,296,565	510	422	**Outside Model Adjustment 3**
2026	Aeroderivative (40 MW)	15.05	1,292,488	516	421	$0
2027	Wind (100 MW)	14.03	1,183,892	480	376	**Outside Model Adjustment 4**
2028	Large GT (187 MW)	14.14	1,163,144	479	370	$0
2029	Large GT (187 MW)	21.34	1,196,027	480	377	**Total Optimized NPV + Adjustments**
2030		19.58	1,245,929	495	388	$7,240,964,781
2031		17.46	1,287,528	488	396	**Average Risk NPV + Adjustments**
2032		15.44	1,300,681	494	398	$7,247,436,170
2033	Solar PV Large (50 MW)	14.24	1,347,728	494	400	
2034	Large GT (187 MW)	20.26	1,352,684	496	400	
2035		18.12	1,421,098	496	413	
2036		15.73	1,584,802	531	454	

Table 67. 2017 IRP: SJGS Retires in 2022 (LOAD = MID, GAS = MID, CO_2 = $20 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,544,650	1,235	1,579	$7,758,111,797
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,133,530	926	1,359	17.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	2,860,167	861	1,202	$7,758,075,950
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,807,502	836	1,133	$234,581,508
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,818,860	816	1,095	55,000,706
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,391,251	724	906	$752,702,618
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.34	1,035,861	444	338	556
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					529
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (41 MW)					27.315
	Solar PV Large (100 MW)					**Outside Adjustment 1**
	Wind (100 MW)					$0
2024	Reciprocating Engines (41 MW)	14.88	1,028,482	451	330	**Outside Adjustment 2**
2025	Solar PV Distribution (50 MW)	14.55	995,089	437	319	$0
2026	Aeroderivative (40 MW)	15.36	1,014,480	447	325	**Outside Model Adjustment 3**
2027	Wind (100 MW)	14.34	870,003	402	270	$0
2028	Large GT (187 MW)	14.44	879,929	409	274	**Outside Model Adjustment 4**
2029	Aeroderivative (40 MW)	14.94	928,084	414	287	$0
2030	Solar PV Large (50 MW)	14.05	889,031	408	269	**Total Optimized NPV + Adjustments**
2031	Large GT (187 MW)	20.28	944,985	407	284	$7,758,111,797
2032		18.22	979,825	418	292	**Average Risk NPV + Adjustments**
2033		16.22	1,014,966	418	296	$7,758,075,950
2034		14.36	1,049,711	427	306	
2035	Aeroderivative (40 MW)	14.69	1,086,105	420	309	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15.29	1,126,759	430	316	

Table 68. 2017 IRP: SJGS Retires in 2022 (LOAD = MID, GAS = MID, $CO_2 = \$40$ NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,067,887	1,127	1,413	$8,557,164,422
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	2,741,048	837	1,188	16.01
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	2,491,750	780	1,047	$8,558,942,133
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,480,594	765	1,000	$372,270,583
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,525,339	753	979	51,312,645
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	17.16	2,016,307	636	746	$1,392,139,401
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
	Wind (100 MW)					516
2023	Data Center1 Solar6 (20 MW)	14.58	892,560	403	286	**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					473
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					24.997
	Reciprocating Engines (41 MW)					**Outside Adjustment 1**
	Solar PV Large (100 MW)					$0
	Wind (100 MW)					**Outside Adjustment 2**
2024	Reciprocating Engines (41 MW)	15.13	891,533	410	280	$0
2025	Solar PV Distribution (50 MW)	14.79	867,513	397	272	**Outside Model Adjustment 3**
2026	Solar PV Large (50 MW)	14.53	849,062	397	263	$0
2027	Solar PV Large (50 MW)	14.10	822,046	379	248	**Outside Model Adjustment 4**
2028	Large GT (187 MW)	14.21	832,882	385	252	$0
2029	Large GT (187 MW)	21.41	875,479	389	264	**Total Optimized NPV + Adjustments**
2030		19.65	875,650	394	260	$8,557,164,422
2031		17.52	930,083	393	275	**Average Risk NPV + Adjustments**
2032		15.51	963,364	403	283	$8,558,942,133
2033	Aeroderivative (40 MW)	15.26	996,221	404	286	
2034	Aeroderivative (40 MW)	15.10	1,030,047	413	296	
2035	Aeroderivative (40 MW)	14.69	1,107,582	416	313	
2036	Rio Bravo CC Expansion (210 MW)	15.29	1,152,429	425	320	

Table 69. 2017 IRP: SJGS Retires in 2022 (LOAD = HIGH, GAS = LOW, CO_2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,128,486,672
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,471,672	993	1,476	15.97
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,081,239	894	1,252	$7,118,365,693
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$147,563,295
2020	Data Center1 Solar3 (30 MW)	14.25	3,006,100	846	1,131	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					77,934,319
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$22,394,702
2021	Data Center1 Solar4 (30 MW)	19.77	3,224,166	845	1,116	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					689
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,908,200	756	936	737
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Aeroderivatives (80 MW)	14.65	1,934,440	552	524	41.735
	1x1 NGCC (250 MW)					**Outside Adjustment 1**
	Data Center1 Solar6 (20 MW)					$0
	Large GT (187 MW)					**Outside Adjustment 2**
	Palo Verde Undepreciated Assets					$0
	Reciprocating Engines (41 MW)					**Outside Model Adjustment 3**
	Solar PV Large (50 MW)					$0
	Solar PV Large (100 MW)					**Outside Model Adjustment 4**
2024	Large GT (187 MW)	19.21	2,133,262	581	550	$0
2025		17.02	2,209,547	578	558	**Total Optimized NPV + Adjustments**
2026		15.47	2,245,380	587	563	$7,128,486,672
2027	Large GT (187 MW)	21.30	2,337,463	594	574	**Average Risk NPV + Adjustments**
2028	Large GT (187 MW)	20.72	2,348,891	593	573	$7,118,365,693
2029		18.93	2,422,568	597	582	
2030		16.90	2,517,285	612	593	
2031		14.62	2,589,331	608	600	
2032	Large GT (187 MW)	19.32	2,646,111	615	605	
2033		17.08	2,794,922	629	621	
2034		14.94	2,844,069	630	625	
2035	Aeroderivative (40 MW)	14.06	2,961,038	635	636	
2036	Small GT (85 MW)	14.48	3,160,522	663	665	

Table 70. 2017 IRP: SJGS Retires in 2022 (LOAD = HIGH, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,956,383,250
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,467,606	993	1,477	15.92
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,070,905	896	1,253	$7,949,786,936
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$250,176,385
2020	Data Center1 Solar3 (30 MW)	14.25	2,990,417	849	1,133	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					70,102,498
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$116,360,413
2021	Data Center1 Solar4 (30 MW)	19.77	3,206,960	848	1,117	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					619
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,901,000	766	944	619
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	1x1 NGCC (250 MW)	14.18	1,640,309	516	451	37.738
	Data Center1 Solar6 (20 MW)					**Outside Adjustment 1**
	Large GT (187 MW)					$0
	Palo Verde Undepreciated Assets					**Outside Adjustment 2**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Reciprocating Engines (41 MW)					**Outside Model Adjustment 3**
	Solar PV Large (50 MW)					$0
2024	Large GT (187 MW)	18.75	1,777,012	535	464	**Outside Model Adjustment 4**
2025		16.57	1,875,826	543	482	$0
2026		15.02	1,927,103	554	491	**Total Optimized NPV + Adjustments**
2027	Solar PV Large (100 MW)	14.78	1,853,217	525	460	$7,956,383,250
2028	Large GT (187 MW)	14.50	1,712,285	500	422	**Average Risk NPV + Adjustments**
	Wind (100 MW)					$7,949,786,936
2029	Aeroderivative (40 MW)	14.55	1,621,441	475	392	
	Wind (100 MW)					
2030	Aeroderivative (40 MW)	14.12	1,652,200	481	392	
2031	Large GT (187 MW)	18.89	1,752,077	484	409	
2032		16.64	1,822,083	495	420	
2033		14.45	1,905,554	499	427	
2034	Large GT (187 MW)	18.97	1,979,088	509	440	
2035		16.63	2,113,412	515	458	
2036		14.11	2,261,929	538	480	

Table 71. 2017 IRP: SJGS Retires in 2022 (LOAD = HIGH, GAS = HIGH, CO_2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,207	1,304	1,682	$8,577,938,031
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,463,429	994	1,478	15.45
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,065,382	897	1,254	$8,572,219,692
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$344,460,287
2020	Data Center1 Solar3 (30 MW)	14.25	2,986,882	850	1,133	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					67,654,787
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$207,902,149
2021	Data Center1 Solar4 (30 MW)	19.77	3,201,386	850	1,118	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					597
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,893,348	768	944	581
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	1x1 NGCC (250 MW)	14.13	1,341,156	465	368	36.410
	Data Center1 Solar6 (20 MW)					**Outside Adjustment 1**
	Large GT (187 MW)					$0
	Palo Verde Undepreciated Assets					**Outside Adjustment 2**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Solar PV Large (50 MW)					**Outside Model Adjustment 3**
	Solar PV Large (100 MW)					$0
	Wind (100 MW)					**Outside Model Adjustment 4**
2024	Large GT (187 MW)	19.33	1,270,654	445	329	$0
	PVNGS U2 Lease Purchase (10 MW)					**Total Optimized NPV + Adjustments**
	Wind (100 MW)					$8,577,938,031
2025		17.15	1,359,500	452	347	**Average Risk NPV + Adjustments**
2026		15.59	1,409,649	464	357	$8,572,219,692
2027	Reciprocating Engines (41 MW)	15.58	1,442,731	457	357	
2028	Large GT (187 MW)	15.09	1,484,846	465	366	
2029	Large GT (187 MW)	20.64	1,571,091	473	382	
2030		18.58	1,601,267	479	382	
2031		16.27	1,702,943	480	399	
2032		14.07	1,774,752	493	411	
2033	Large GT (187 MW)	18.66	1,858,974	497	418	
2034		16.49	1,926,444	507	430	
2035		14.20	2,067,914	513	450	
2036	Small GT (85 MW)	14.62	2,201,776	533	469	

Table 72. 2017 IRP: SJGS Retires in 2022 (LOAD = HIGH, GAS = MID, CO_2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,819,999,719
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,467,606	993	1,477	15.68
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,070,905	896	1,253	$7,811,435,867
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$288,790,746
2020	Data Center1 Solar3 (30 MW)	14.25	2,990,417	849	1,133	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					75,337,757
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$0
2021	Data Center1 Solar4 (30 MW)	19.77	3,206,960	848	1,117	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					666
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,900,217	766	944	687
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Aeroderivatives (80 MW)	14.65	1,877,743	563	518	40.192
	1x1 NGCC (250 MW)					**Outside Adjustment 1**
	Data Center1 Solar6 (20 MW)					$0
	Large GT (187 MW)					**Outside Adjustment 2**
	Palo Verde Undepreciated Assets					$0
	Reciprocating Engines (41 MW)					**Outside Model Adjustment 3**
	Solar PV Large (50 MW)					$0
	Solar PV Large (100 MW)					**Outside Model Adjustment 4**
2024	Large GT (187 MW)	19.21	2,076,564	592	544	$0
2025		17.02	2,142,497	591	552	**Total Optimized NPV + Adjustments**
2026		15.47	2,180,304	599	556	$7,819,999,719
2027	Wind (100 MW)	14.02	2,091,019	569	520	**Average Risk NPV + Adjustments**
2028	Aeroderivative (40 MW)	15.13	2,097,372	571	520	$7,811,435,867
	Large GT (187 MW)					
2029	Large GT (187 MW)	20.87	1,980,573	541	482	
	Wind (100 MW)					
2030		18.81	2,068,671	556	494	
2031		16.49	2,140,503	553	503	
2032		14.29	2,196,994	561	509	
2033	Large GT (187 MW)	18.88	2,342,131	574	527	
2034		16.70	2,383,178	578	532	
2035		14.41	2,509,361	581	545	
2036	Small GT (85 MW)	14.82	2,701,311	609	575	

Table 73. 2017 IRP: SJGS Retires in 2022 (LOAD = HIGH, GAS = MID, CO_2 = $8 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,827,045	1,294	1,666	$8,231,061,531
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,413,728	979	1,450	15.55
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,050,676	888	1,240	$8,221,225,037
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$249,013,890
2020	Data Center1 Solar3 (30 MW)	14.25	2,996,736	848	1,132	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					68,105,777
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$358,194,702
2021	Data Center1 Solar4 (30 MW)	19.77	3,209,477	848	1,117	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					601
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,902,408	766	944	594
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	1x1 NGCC (250 MW)	14.13	1,364,713	460	371	36.642
	Data Center1 Solar6 (20 MW)					**Outside Adjustment 1**
	Large GT (187 MW)					$0
	Palo Verde Undepreciated Assets					**Outside Adjustment 2**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Solar PV Large (50 MW)					**Outside Model Adjustment 3**
	Solar PV Large (100 MW)					$0
	Wind (100 MW)					**Outside Model Adjustment 4**
2024	Large GT (187 MW)	18.70	1,495,219	479	387	$0
2025		16.53	1,590,753	486	406	**Total Optimized NPV + Adjustments**
2026		14.98	1,638,788	498	415	$8,231,061,531
2027	Reciprocating Engines (41 MW)	15.18	1,494,773	459	368	**Average Risk NPV + Adjustments**
	Wind (100 MW)					$8,221,225,037
2028	Large GT (187 MW)	14.70	1,538,599	468	378	
2029	Aeroderivative (40 MW)	14.55	1,622,284	475	392	
2030	Aeroderivative (40 MW)	14.12	1,653,195	481	392	
2031	Large GT (187 MW)	18.89	1,755,368	483	410	
2032		16.64	1,825,368	494	420	
2033		14.45	1,911,749	498	427	
2034	Large GT (187 MW)	18.97	1,983,715	508	440	
2035		16.63	2,118,741	514	458	
2036		14.11	2,268,367	537	481	

Table 74. 2017 IRP: SJGS Retires in 2022 (LOAD = HIGH, GAS = MID, CO_2 = $20 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,580,356	1,237	1,579	$8,819,688,781
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,201,935	930	1,358	15.49
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	2,871,672	848	1,165	$8,799,660,385
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$300,204,051
2020	Data Center1 Solar3 (30 MW)	14.25	2,873,062	819	1,081	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					66,327,519
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$867,746,450
2021	Data Center1 Solar4 (30 MW)	19.77	3,083,911	819	1,069	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					585
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,843,772	749	920	575
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	1x1 NGCC (250 MW)	14.13	1,378,957	457	373	35.459
	Data Center1 Solar6 (20 MW)					**Outside Adjustment 1**
	Large GT (187 MW)					$0
	Palo Verde Undepreciated Assets					**Outside Adjustment 2**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Solar PV Large (50 MW)					**Outside Model Adjustment 3**
	Solar PV Large (100 MW)					$0
	Wind (100 MW)					**Outside Model Adjustment 4**
2024	Large GT (187 MW)	18.91	1,337,359	444	343	$0
	Wind (100 MW)					**Total Optimized NPV + Adjustments**
2025		16.74	1,430,997	451	362	$8,819,688,781
2026		15.19	1,480,148	463	371	**Average Risk NPV + Adjustments**
2027	Reciprocating Engines (41 MW)	15.18	1,509,295	457	370	$8,799,660,385
2028	Large GT (187 MW)	14.70	1,553,215	465	379	
2029	Aeroderivative (40 MW)	14.55	1,635,927	472	394	
2030	Aeroderivative (40 MW)	14.12	1,666,542	478	394	
2031	Large GT (187 MW)	18.89	1,765,907	480	411	
2032		16.64	1,835,589	492	421	
2033		14.45	1,918,305	496	428	
2034	Large GT (187 MW)	18.97	1,992,428	506	441	
2035		16.63	2,125,029	512	459	
2036		14.11	2,273,164	535	481	

Table 75. 2017 IRP: SJGS Retires in 2022 (LOAD = HIGH, GAS = MID, CO_2 = $40 NMPRC)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,098,453	1,128	1,413	$9,751,297,250
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	2,799,363	840	1,187	15.25
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	2,503,345	768	1,016	$9,728,805,064
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$427,901,213
2020	Data Center1 Solar3 (30 MW)	14.25	2,528,213	746	950	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					62,793,140
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$1,626,183,184
2021	Data Center1 Solar4 (30 MW)	19.77	2,748,714	751	951	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					554
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	17.18	2,382,171	654	758	535
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
	Wind (100 MW)					33.116
2023	1x1 NGCC (250 MW)	14.35	1,242,825	419	332	**Outside Adjustment 1**
	Data Center1 Solar6 (20 MW)					$0
	Large GT (187 MW)					**Outside Adjustment 2**
	Palo Verde Undepreciated Assets					$0
	PVNGS U1 Lease Purchase (104 MW)					**Outside Model Adjustment 3**
	Solar PV Large (50 MW)					$0
	Solar PV Large (100 MW)					**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2024	Large GT (187 MW)	19.33	1,332,878	432	338	**Total Optimized NPV + Adjustments**
	PVNGS U2 Lease Purchase (10 MW)					$9,751,297,250
2025		17.15	1,423,457	439	357	**Average Risk NPV + Adjustments**
2026		15.59	1,475,157	451	367	$9,728,805,064
2027	Reciprocating Engines (41 MW)	15.58	1,503,592	445	366	
2028	Large GT (187 MW)	15.09	1,545,166	453	374	
2029	Large GT (187 MW)	20.64	1,629,662	460	389	
2030		18.58	1,658,608	467	389	
2031		16.27	1,754,270	469	405	
2032		14.07	1,827,130	481	416	
2033	Large GT (187 MW)	18.66	1,907,597	485	423	
2034		16.49	1,976,918	495	434	
2035		14.20	2,112,539	502	453	
2036	Small GT (85 MW)	14.62	2,246,005	522	472	

APPENDIX N. MCEP LOADS (MW) AND RESOURCES TABLE

Table 76. MCEP Loads (MW) and Resources

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Forecasted System Peak Demand	1,911	1,961	2,009	2,056	2,108	2,154	2,189	2,219	2,249	2,280	2,312	2,344	2,378	2,413	2,448	2,485	2,522	2,560	2,599	2,638
Forecasted Incremental Energy Efficiency	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)	(136)	(138)	(146)	(147)	(142)	(138)	(135)	(134)	(129)	(122)
Forecasted Incremental Customer Sited PV	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(47)	(48)
Net System Peak Demand	1,871	1,900	1,926	1,961	1,999	2,033	2,053	2,071	2,093	2,114	2,138	2,168	2,193	2,225	2,265	2,304	2,343	2,381	2,423	2,468
Four Corners	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	-	-	-	-	-
San Juan	783	497	497	497	497	497	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Coal Resources	983	697	697	697	697	697	200	200	200	200	200	200	200	200	200	-	-	-	-	-
Palo Verde Units 1 & 2	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268
Palo Verde Unit 3	-	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
Total Nuclear Resources	268	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402
Reeves	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
Afton	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
Lordsburg	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Luna	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189
Rio Bravo	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	-
Valencia	150	150	150	150	150	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-
La Luz	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Natural Gas-Fired Resource (intermediate)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187	187	187
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	40	40	40	40	40	40	40	40	40	40	40
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
Natural Gas-Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
Total Natural Gas Resources	981	981	981	981	981	981	1,437	1,437	1,437	1,477	1,477	1,514	1,514	1,701	1,701	1,888	1,888	1,928	1,968	2,040
Total Demand Response Programs (Net of losses)	45	47	48	50	51	53	54	56	57	59	60	60	60	60	60	60	60	60	60	60

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Wind Purchase (NMWEC)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Wind Purchase (Red Mesa)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
Prosperity Battery Demo	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Utility Scale Solar PV (22 MW - 2012 REPP)	12	12	12	12	12	12	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Utility Scale Solar PV (20 MW - 2013 REPP)	11	11	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	10
Utility Scale Solar PV (23 MW - 2014 REPP)	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14	14	14
Utility Scale Solar PV (40 MW - 2015 REPP)	30	30	30	30	29	29	29	29	28	28	28	28	28	27	27	27	27	27	26	26
PNM Sky Blue - 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dale Burgett Geothermal Plant	1	1	5	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18
100 MW Solar PV	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35
50 MW Solar PV	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18
Data Center 1 Solar PV - 20 MW	-	-	-	-	-	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Data Center 1 Solar PV - 40 MW	-	-	-	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Solar PV - 30 MW	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Solar PV - 40 MW	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Wind - 30 MW	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Data Center 1 Wind - 50 MW	-	-	-	-	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Solar PV for 2020 RPS	-	-	7	18	17	17	17	17	17	17	17	17	16	16	16	16	16	16	16	16
Wind for 2020 RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Renewable Resources	86	108	151	189	213	244	255	272	307	306	306	305	327	327	326	331	330	330	346	341
Total System Resources	2,363	2,235	2,279	2,318	2,344	2,377	2,348	2,367	2,403	2,444	2,445	2,481	2,503	2,690	2,689	2,681	2,680	2,720	2,776	2,843
Reserve Margin	**492**	**335**	**353**	**357**	**344**	**344**	**296**	**296**	**310**	**330**	**307**	**313**	**310**	**465**	**425**	**377**	**337**	**339**	**353**	**375**
Reserve Margin (%)	**26.3%**	**17.6%**	**18.3%**	**18.2%**	**17.2%**	**16.9%**	**14.4%**	**14.3%**	**14.8%**	**15.6%**	**14.4%**	**14.5%**	**14.2%**	**20.9%**	**18.7%**	**16.4%**	**14.4%**	**14.2%**	**14.6%**	**15.2%**

Table 77. Alternate Portfolio – PVNGS Leased Capacity Loads and Resources Table

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Forecasted System Peak Demand	1,911	1,961	2,009	2,056	2,108	2,154	2,189	2,219	2,249	2,280	2,312	2,344	2,378	2,413	2,448	2,485	2,522	2,560	2,599	2,638
Forecasted Incremental Energy Efficiency	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)	(136)	(138)	(146)	(147)	(142)	(138)	(135)	(134)	(129)	(122)
Forecasted Incremental Customer Sited PV	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(47)	(48)
Net System Peak Demand	1,871	1,900	1,926	1,961	1,999	2,033	2,053	2,071	2,093	2,114	2,138	2,168	2,193	2,225	2,265	2,304	2,343	2,381	2,423	2,468
Four Corners	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	-	-	-	-	-
San Juan	783	497	497	497	497	497	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Coal Resources	983	697	697	697	697	697	200	200	200	200	200	200	200	200	200	-	-	-	-	-
Palo Verde Units 1 & 2	268	268	268	268	268	268	164	154	154	154	154	154	154	154	154	154	154	154	154	154
Palo Verde Unit 3	-	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
Total Nuclear Resources	268	402	402	402	402	402	298	288	288	288	288	288	288	288	288	288	288	288	288	288
Reeves	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
Afton	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
Lordsburg	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Luna	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189
Rio Bravo	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	-
Valencia	150	150	150	150	150	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-
La Luz	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41	41
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41	41	41
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187
Natural Gas Fired Resource (intermediate)	-	-	-	-	-	-	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
Total Natural Gas Resources	981	981	981	981	981	981	1,605	1,605	1,605	1,605	1,605	1,642	1,642	1,642	1,829	2,016	2,016	2,057	2,098	2,138
Total Demand Response Programs (Net of losses)	45	47	48	50	51	53	54	56	57	59	60	60	60	60	60	60	60	60	60	60

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Wind Purchase (NMWEC)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Wind Purchase (Red Mesa)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
Prosperity Battery Demo	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Utility Scale Solar PV (22 MW - 2012 REPP)	12	12	12	12	12	12	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Utility Scale Solar PV (20 MW - 2013 REPP)	11	11	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	10
Utility Scale Solar PV (23 MW - 2014 REPP)	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14	14	14
Utility Scale Solar PV (40 MW - 2015 REPP)	30	30	30	30	29	29	29	29	28	28	28	28	28	27	27	27	27	27	26	26
PNM Sky Blue - 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dale Burgett Geothermal Plant	1	1	5	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18
100 MW Solar PV	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35
50 MW Solar PV	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18
100 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18
50 MW Solar PV	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18
Data Center 1 Solar PV - 20 MW	-	-	-	-	-	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Data Center 1 Solar PV - 40 MW	-	-	-	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Solar PV - 30 MW	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Solar PV - 40 MW	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total Renewable Resources	86	108	151	189	213	244	255	255	254	271	288	293	315	349	349	348	348	347	346	341
Total System Resources	2,363	2,235	2,279	2,318	2,344	2,377	2,412	2,403	2,404	2,423	2,441	2,483	2,505	2,539	2,726	2,712	2,712	2,752	2,792	2,827
Reserve Margin	**492**	**335**	**353**	**357**	**344**	**344**	**360**	**332**	**311**	**309**	**303**	**315**	**312**	**314**	**461**	**408**	**369**	**372**	**369**	**359**
Reserve Margin (%)	26.3%	17.6%	18.3%	18.2%	17.2%	16.9%	17.5%	16.1%	14.9%	14.6%	14.2%	14.5%	14.2%	14.1%	20.4%	17.7%	15.7%	15.6%	15.2%	14.5%

Table 78. Alternate Portfolio – Continue Coal Baseload Loads and Resources Table

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Forecasted System Peak Demand	1,911	1,961	2,009	2,056	2,108	2,154	2,189	2,219	2,249	2,280	2,312	2,344	2,378	2,413	2,448	2,485	2,522	2,560	2,599	2,638
Forecasted Incremental Energy Efficiency	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)	(136)	(138)	(146)	(147)	(142)	(138)	(135)	(134)	(129)	(122)
Forecasted Incremental Customer Sited PV	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(47)	(48)
Net System Peak Demand	1,871	1,900	1,926	1,961	1,999	2,033	2,053	2,071	2,093	2,114	2,138	2,168	2,193	2,225	2,265	2,304	2,343	2,381	2,423	2,468
Four Corners	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
San Juan	783	497	497	497	497	497	497	497	497	497	497	497	497	497	497	497	497	497	497	497
Total Coal Resources	983	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697	697
Palo Verde Units 1 & 2	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268
Palo Verde Unit 3	-	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
Total Nuclear Resources	268	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402
Reeves	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
Afton	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
Lordsburg	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Luna	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189
Rio Bravo	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	-
Valencia	150	150	150	150	150	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-
La Luz	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41	41	41	41	41	41
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	41	41	41	41	41	41	41
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
Total Natural Gas Resources	981	981	981	981	981	981	1,168	1,168	1,168	1,168	1,168	1,205	1,205	1,246	1,287	1,474	1,474	1,474	1,474	1,514
Total Demand Response Programs (Net of losses)	45	47	48	50	51	53	54	56	57	59	60	60	60	60	60	60	60	60	60	60

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Wind Purchase NMWEC)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Wind Purchase(RdMesa)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
Prosperity Battery Demo	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Utility Scale Solar PV (22 MW - 2012 REPP)	12	12	12	12	12	12	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Utility Scale Solar PV (20 MW - 2013 REPP)	11	11	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	10
Utility Scale Solar PV (23 MW - 2014 REPP)	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14	14	14
Utility Scale Solar PV (40 MW - 2015 REPP)	30	30	30	30	29	29	29	29	28	28	28	28	28	27	27	27	27	27	26	26
PNM Sky Blue - 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dale Burgett Geothermal	1	1	5	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18
100 MW Solar PV	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35
50 MW Solar PV	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18
Data Center 1 Solar PV - 20 MW	-	-	-	-	-	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Data Center 1 Solar PV - 40 MW	-	-	-	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Solar PV - 30 MW	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Solar PV - 40 MW	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Wind - 30 MW	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Data Center 1 Wind - 50 MW	-	-	-	-	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
50 MW Solar PV for RPS	-	-	7	18	17	17	17	17	17	17	17	17	16	16	16	16	16	16	16	16
NMWEC Repower/RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Renewable Resources	86	108	151	189	213	244	255	255	254	254	253	253	270	269	269	268	268	267	266	278
Total System Resources	2,363	2,235	2,279	2,318	2,344	2,377	2,472	2,463	2,464	2,465	2,466	2,503	2,520	2,560	2,601	2,787	2,787	2,786	2,785	2,837
Reserve Margin	**492**	**335**	**353**	**357**	**344**	**344**	**336**	**408**	**381**	**360**	**340**	**317**	**323**	**315**	**324**	**472**	**432**	**394**	**350**	**357**
Reserve Margin (%)	26.3%	17.6%	18.3%	18.2%	17.2%	16.5%	19.8%	18.3%	17.1%	16.0%	14.7%	14.8%	14.3%	14.5%	14.3%	20.4%	18.4%	16.5%	14.4%	14.4%

Table 79. Alternate Portfolio – Higher than 50% Renewable Energy Use Loads and Resources Table

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Forecasted System Peak Demand	1,911	1,961	2,009	2,056	2,108	2,154	2,189	2,219	2,249	2,280	2,312	2,344	2,378	2,413	2,448	2,485	2,522	2,560	2,599	2,638
Forecasted Incremental Energy Efficiency	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)	(136)	(138)	(146)	(147)	(142)	(138)	(135)	(134)	(129)	(122)
Forecasted Incremental Customer Sited PV	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(47)	(48)
Net System Peak Demand	1,871	1,900	1,926	1,961	1,999	2,033	2,053	2,071	2,093	2,114	2,138	2,168	2,193	2,225	2,265	2,304	2,343	2,381	2,423	2,468
Four Corners	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	-	-	-	-	-
San Juan	783	497	497	497	497	497	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Coal Resources	983	697	697	697	697	697	200	200	200	200	200	200	200	200	200	-	-	-	-	-
Palo Verde Units 1 & 2	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268	268
Palo Verde Unit 3	-	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
Total Nuclear Resources	268	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402	402
Reeves	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
Afton	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230
Lordsburg	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Luna	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189	189
Rio Bravo	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	-
Valencia	150	150	150	150	150	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-
La Luz	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40	40	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	40	40	40	40	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	41	41	41	41	41	41	41	41	41	41	41	41	41
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187	187	187	187	187	187	187	187	187	187	187
Total Natural Gas Resources	981	981	981	981	981	981	1,396	1,437	1,437	1,437	1,437	1,474	1,474	1,474	1,514	1,741	1,741	1,781	1,968	1,968
Total Demand Response Programs (Net of losses)	45	47	48	50	51	53	54	56	57	59	60	60	60	60	60	60	60	60	60	60

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Wind Purchase NMWEC)	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Wind Purchase(RdMesa)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
Prosperity Battery Demo	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Utility Scale Solar PV (22 MW - 2012 REPP)	12	12	12	12	12	12	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Utility Scale Solar PV (20 MW - 2013 REPP)	11	11	11	11	11	11	11	10	10	10	10	10	10	10	10	10	10	10	10	10
Utility Scale Solar PV (23 MW - 2014 REPP)	16	15	15	15	15	15	15	15	15	15	15	15	15	15	15	14	14	14	14	14
Utility Scale Solar PV (40 MW - 2015 REPP)	30	30	30	30	29	29	29	29	28	28	28	28	28	27	27	27	27	27	26	26
PNM Sky Blue - 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dale Burgett Geothermal	1	1	5	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
100 MW Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18
100 MW Solar PV	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35	35
50 MW Solar PV	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18
50 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18	18	18
100 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35
100 MW Solar PV	-	-	-	-	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35
100 MW Solar PV	-	-	-	-	-	-	-	-	-	35	35	35	35	35	35	35	35	35	35	35
50 MW Solar PV	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18
50 MW Solar PV	-	-	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18
100 MW Wind	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5
100 MW Wind	-	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5
50 MW Solar PV	-	-	-	-	-	-	18	18	18	18	18	18	18	18	18	18	18	18	18	18
100 MW Wind	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
100 MW Wind	-	-	-	-	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Data Center 1 Solar PV - 20 MW	-	-	-	-	-	-	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Data Center 1 Solar PV - 40 MW	-	-	-	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Solar PV - 30 MW	-	-	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Solar PV - 40 MW	-	-	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Data Center 1 Wind - 30 MW	-	-	-	-	-	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Data Center 1 Wind - 50 MW	-	-	-	-	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Data Center 1 Wind - 50	-	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MW																				
50 MW Solar PV for RPS	-	-	7	18	17	17	17	17	17	17	17	17	16	16	16	16	16	16	16	16
NMWEC Repower for RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Renewable Resources	86	108	151	189	213	254	293	292	327	361	361	360	395	429	429	428	480	480	479	473
Total System Resources	2,363	2,235	2,279	2,318	2,344	2,387	2,345	2,387	2,423	2,459	2,460	2,496	2,531	2,565	2,605	2,631	2,683	2,723	2,909	2,903
Reserve Margin	492	335	353	357	344	354	292	316	330	345	322	328	338	340	340	327	340	342	486	435
Reserve Margin (%)	26.3%	17.6%	18.3%	18.2%	17.2%	17.4%	14.2%	15.3%	15.8%	16.3%	15.1%	15.1%	15.4%	15.3%	15.0%	14.2%	14.5%	14.4%	20.0%	17.6%

APPENDIX O. Detailed Results of Sensitivity Analysis

Table 80. 2017 IRP: SJGS Continues Beyond 2022 - With PVNGS Lease Purchases included (U1 & U2) (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,285,698,016
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.6	3,379,700	987	1,477	31.90
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,283,879,132
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$71,808,495
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	85,225,792
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$155,383,927
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	15.73	2,839,310	795	903	860
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
	PVNGS U1 Lease Purchase (104 MW)					1021
2024	PVNGS U2 Lease Purchase (10 MW)	14.77	2,823,533	794	877	**20-Year Freshwater (Bn of Gal)**
2025	Reciprocating Engines (41 MW)	15.55	2,928,693	812	913	48.688
2026		14.46	2,921,854	817	915	**Outside Adjustment 1**
2027	Reciprocating Engines (41 MW)	15.13	2,966,230	815	911	$0
2028	Large GT (187 MW)	15.22	2,983,043	818	919	**Outside Adjustment 2**
2029	Aeroderivative (40 MW)	15.71	3,019,098	822	926	$0
2030		14.04	3,008,410	823	913	**Outside Model Adjustment 3**
2031	Large GT (187 MW)	20.24	3,116,862	828	937	$0
2032		18.18	3,212,095	845	955	**Outside Model Adjustment 4**
2033		16.20	3,272,998	848	952	$0
2034		14.35	3,312,799	854	963	**Total Optimized NPV + Adjustments**
2035	Aeroderivative (40 MW)	14.68	3,322,331	839	946	$7,285,698,016
	Solar PV Distribution (50 MW)					**Average Risk NPV + Adjustments**
2036	Aeroderivative (40 MW)	14.68	3,418,391	855	955	$7,283,879,132
	Solar PV Large (50 MW)					

Table 81. 2017 IRP: SJGS Continues Beyond 2022 - PVNGS Lease Purchases not available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,145,621,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	31.65
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,142,442,737
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,947,265
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,715,837
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,943,162
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1171
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.622
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Large GT (187 MW)	20.99	3,580,246	947	1,104	**Outside Model Adjustment 3**
2031		18.85	3,642,256	942	1,110	$0
2032		16.82	3,699,112	951	1,117	**Outside Model Adjustment 4**
2033		14.86	3,850,884	969	1,134	$0
2034	Reciprocating Engines (41 MW)	14.74	3,830,596	962	1,127	**Total Optimized NPV + Adjustments**
2035	Reciprocating Engines (41 MW)	14.39	3,910,751	961	1,128	$7,145,621,594
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,142,442,737

Table 82. 2017 IRP: SJGS Continues Beyond 2022 - SJGS Low Coal Pricing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,113,190,234
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.25
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,110,276,444
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,441,407
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,782
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,840,006
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,615	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,724	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,476	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,113,190,234
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,110,276,444

Table 83. 2017 IRP: SJGS Continues Beyond 2022 - SJGS High Coal Pricing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,218,745,688
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	31.87
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,215,108,777
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,581,272
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,103
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,838,291
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,822	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,675	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,477	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,633,005	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,128	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,283	967	1,131	$0
2034		16.46	3,825,788	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,781	961	1,128	$7,218,745,688
2036	Aeroderivative (40 MW)	14.40	4,075,341	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,215,108,777

Table 84. 2017 IRP: SJGS Continues Beyond 2022 -With PACE REF Market (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	6,487,258	1,360	1,658	$6,895,562,375
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	4,715,118	1,065	1,458	2.91
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	4,799,986	1,044	1,386	$6,827,550,883
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	4,626,821	997	1,291	$108,991,636
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	4,582,667	971	1,247	124,183,660
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	4,703,814	965	1,223	$230,590,720
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	4,902,924	1,025	1,200	1042
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1241
2024		18.27	4,916,367	1,045	1,209	**20-Year Freshwater (Bn of Gal)**
2025		17.07	4,972,202	1,043	1,214	66.035
2026		15.97	4,867,590	1,038	1,204	**Outside Adjustment 1**
2027		14.72	4,925,429	1,043	1,208	$0
2028	Large GT (187 MW)	14.81	5,081,964	1,047	1,214	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	4,944,307	1,018	1,172	$0
2030	Reciprocating Engines (41 MW)	14.46	4,934,430	1,021	1,165	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	5,054,399	1,020	1,174	$0
2032	Large GT (187 MW)	20.37	5,151,955	1,031	1,186	**Outside Model Adjustment 4**
2033		18.34	5,147,616	1,031	1,178	$0
2034		16.46	5,180,499	1,034	1,186	**Total Optimized NPV + Adjustments**
2035		14.39	5,175,512	1,022	1,174	$6,895,562,375
2036	Aeroderivative (40 MW)	14.40	5,303,700	1,042	1,187	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$6,827,550,883

Table 85. 2017 IRP: SJGS Continues Beyond 2022 - FCPP Exit in 2031 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,092,972,609
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	30.91
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,090,349,146
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$95,404,324
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	89,994,615
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$167,151,382
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	915
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1147
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	50.409
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Aeroderivative (40 MW)	14.21	4,449,674	873	1,137	**Outside Model Adjustment 4**
	Four Corners Undepreciated Assets					$0
	Large GT (187 MW)					**Total Optimized NPV + Adjustments**
	Solar PV Large (50 MW)					$7,092,972,609
2033	Aeroderivative (40 MW)	14.20	4,305,391	837	1,076	**Average Risk NPV + Adjustments**
	Wind (100 MW)					$7,090,349,146
2034	Aeroderivative (40 MW)	14.05	4,313,730	830	1,073	
2035	Solar PV Large (50 MW)	14.18	4,057,480	770	992	
	Solar PV Large (100 MW)					
2036	Large GT (187 MW)	19.42	4,340,080	817	1,043	

Table 86. 2017 IRP: SJGS Continues Beyond 2022 - PVNGS Low Fuel and O&M (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,010,699,469
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,007,597,983
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,473,542
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,663
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,839,696
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,010,699,469
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,007,597,983

Table 87. 2017 IRP: SJGS Continues Beyond 2022 - PVNGS High Fuel and O&M (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,233,283,953
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,230,182,572
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,473,560
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,663
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,839,696
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,233,283,953
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,230,182,572

Table 88. 2017 IRP: SJGS Continues Beyond 2022 - No Renewable Integration Costs (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,145,293,672
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.33
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,162,541,946
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$82,473,551
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,478,414
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,417,373
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	950
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1166
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.545
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,145,293,672
2036	Solar PV Large (50 MW)	14.20	3,881,317	949	1,094	**Average Risk NPV + Adjustments**
	Solar PV Large (100 MW)					$7,162,541,946

Table 89. 2017 IRP: SJGS Continues Beyond 2022 - No Demand Response (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,123,068,422
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	15.16	3,379,018	987	1,476	25.97
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	15.83	3,117,255	921	1,314	$7,196,397,408
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	15.65	2,868,248	857	1,171	$87,803,633
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	14.66	2,834,863	828	1,116	94,555,795
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	15.87	2,879,463	820	1,080	$178,141,499
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
	Reciprocating Engines (41 MW)					961
2023	Data Center1 Solar6 (20 MW)	19.12	3,428,838	930	1,117	**20-Year PNM NM CO2 (lbs/MWh)**
	Large GT (187 MW)					1185
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
2024		17.58	3,552,888	961	1,135	53.134
2025		16.31	3,525,933	950	1,129	**Outside Adjustment 1**
2026		15.15	3,492,309	949	1,122	$0
2027	Reciprocating Engines (41 MW)	15.74	3,637,390	966	1,143	**Outside Adjustment 2**
2028	Large GT (187 MW)	15.82	3,578,293	954	1,131	$0
2029		14.49	3,592,672	950	1,125	**Outside Model Adjustment 3**
2030	Aeroderivative (40 MW)	14.62	3,679,855	969	1,138	$0
2031	Aeroderivative (40 MW)	14.35	3,737,274	963	1,143	**Outside Model Adjustment 4**
2032	Aeroderivative (40 MW)	14.12	3,794,682	972	1,150	$0
2033	Large GT (187 MW)	20.15	3,945,132	989	1,164	**Total Optimized NPV + Adjustments**
2034		18.23	3,929,504	983	1,159	$7,123,068,422
2035		16.13	4,023,507	983	1,163	**Average Risk NPV + Adjustments**
2036	Solar PV Distribution (50 MW)	14.50	4,173,557	1,009	1,185	$7,196,397,408

Table 90. 2017 IRP: SJGS Continues Beyond 2022 - 2017 IRP Low EE Forecast (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.28	4,822,956	1,302	1,682	$7,156,090,516
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.55	3,384,223	987	1,477	32.82
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.23	3,125,787	922	1,315	$7,157,484,106
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.03	2,880,528	858	1,172	$88,584,891
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.01	2,852,546	830	1,118	95,296,369
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.16	2,837,619	808	1,057	$180,004,113
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.37	3,465,373	934	1,121	961
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1182
2024		17.82	3,596,641	965	1,140	**20-Year Freshwater (Bn of Gal)**
2025		16.54	3,576,331	954	1,135	53.359
2026		15.36	3,551,463	954	1,128	**Outside Adjustment 1**
2027		14.02	3,708,941	972	1,151	$0
2028	Large GT (187 MW)	14.03	3,655,563	961	1,139	**Outside Adjustment 2**
2029	Large GT (187 MW)	21.03	3,679,592	958	1,134	$0
2030		19.21	3,774,179	977	1,146	**Outside Model Adjustment 3**
2031		17.08	3,838,901	971	1,152	$0
2032		15.07	3,900,094	980	1,159	**Outside Model Adjustment 4**
2033	Reciprocating Engines (41 MW)	14.85	4,044,639	996	1,171	$0
2034	Reciprocating Engines (41 MW)	14.68	4,027,299	989	1,165	**Total Optimized NPV + Adjustments**
2035	Solar PV Large (50 MW)	14.06	3,910,328	947	1,103	$7,156,090,516
	Solar PV Distribution (50 MW)					**Average Risk NPV + Adjustments**
2036	Aeroderivative (40 MW)	14.08	4,076,363	975	1,130	$7,157,484,106
	Solar PV Large (50 MW)					

Table 91. 2017 IRP: SJGS Continues Beyond 2022 - 2017 IRP High EE Forecast (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,419	1,302	1,682	$7,122,257,281
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.60	3,379,667	987	1,477	31.84
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.33	3,117,070	921	1,314	$7,129,335,300
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.19	2,866,498	857	1,171	$86,400,291
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.25	2,831,168	827	1,116	93,791,940
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.50	2,808,364	805	1,053	$176,182,497
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.87	3,421,587	930	1,117	959
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1185
2024		18.46	3,541,254	961	1,135	**20-Year Freshwater (Bn of Gal)**
2025		17.32	3,508,251	949	1,129	52.732
2026		16.29	3,467,721	947	1,121	**Outside Adjustment 1**
2027		15.11	3,609,601	965	1,143	$0
2028	Large GT (187 MW)	15.29	3,543,092	952	1,130	**Outside Adjustment 2**
2029		14.07	3,549,211	948	1,124	$0
2030	Reciprocating Engines (41 MW)	14.36	3,622,003	966	1,135	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.21	3,667,119	958	1,138	$0
2032	Aeroderivative (40 MW)	14.07	3,715,530	966	1,144	**Outside Model Adjustment 4**
2033	Large GT (187 MW)	20.23	3,860,209	984	1,160	$0
2034		18.41	3,835,955	977	1,154	**Total Optimized NPV + Adjustments**
2035		16.35	3,921,078	977	1,157	$7,122,257,281
2036		14.04	4,176,440	1,026	1,214	**Average Risk NPV + Adjustments**
						$7,129,335,300

Table 92. 2017 IRP: SJGS Continues Beyond 2022 - No EE or DR beginning 2018 (LOAD = MID, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	24.76	4,972,419	1,310	1,682	$7,217,109,000
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	2nd Aeroderivative (40 MW)	15.06	3,585,369	1,003	1,480	27.72
	Data Center1 Solar1 (30 MW)					**Risk Porfolio Average (NPV)**
	Data Center1 Wind1 (50 MW)					$7,423,837,042
2019	Data Center1 Solar2 (40 MW)	14.85	3,418,692	952	1,342	**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$95,183,478
2020	Data Center1 Solar3 (30 MW)	14.04	3,247,248	898	1,219	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					104,000,681
2021	Data Center1 Solar4 (30 MW)	14.33	3,280,270	875	1,172	**20-Year CO2 Cost (NPV)**
	Data Center1 Wind3 (50 MW)					$198,115,195
	Reciprocating Engines (41 MW)					**20-Year PNM CO2 (lbs/MWh)**
2022	Aeroderivative (40 MW)	14.76	3,331,593	864	1,130	982
	Data Center1 Solar5 (40 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Data Center1 Wind4 (30 MW)					1191
2023	Data Center1 Solar6 (20 MW)	17.14	3,955,810	970	1,155	**20-Year Freshwater (Bn of Gal)**
	Large GT (187 MW)					57.324
	Palo Verde Undepreciated Assets					**Outside Adjustment 1**
2024		15.16	4,103,627	998	1,169	$0
2025	Reciprocating Engines (41 MW)	15.47	4,112,508	990	1,167	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.69	4,122,597	991	1,161	$0
2027		14.10	4,276,973	1,005	1,176	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.11	4,235,060	997	1,170	$0
2029	Large GT (187 MW)	20.46	4,252,700	991	1,159	**Outside Model Adjustment 4**
2030		18.74	4,334,471	1,005	1,166	$0
2031		17.03	4,401,098	1,002	1,174	**Total Optimized NPV + Adjustments**
2032		15.33	4,452,373	1,010	1,182	$7,217,109,000
2033	Solar PV Distribution (50 MW)	14.34	4,455,728	1,000	1,157	**Average Risk NPV + Adjustments**
2034	Solar PV Large (100 MW)	14	4,239,800	959	1,101	$7,423,837,042
2035	Aeroderivative (40 MW)	14	4,036,950	907	1,030	
	Wind (100 MW)					
2036	Large GT (187 MW)	19	4,277,910	951	1,079	

Table 93. 2017 IRP: SJGS Continues Beyond 2022 - No EE (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	24.76	4,972,419	1,310	1,682	$7,147,454,781
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	15.40	3,572,726	1,001	1,475	44.34
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	15.26	3,389,038	945	1,330	$7,363,303,134
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	14.51	3,204,190	889	1,201	$87,799,092
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	14.86	3,281,229	876	1,172	100,254,278
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
	Reciprocating Engines (41 MW)					$188,703,961
2022	Data Center1 Solar5 (40 MW)	14.30	3,238,776	843	1,092	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind4 (30 MW)					945
	Solar PV Distribution (50 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	16.74	3,844,878	947	1,121	1134
	Large GT (187 MW)					**20-Year Freshwater (Bn of Gal)**
	Palo Verde Undepreciated Assets					55.574
2024		14.84	3,999,416	977	1,137	**Outside Adjustment 1**
2025	Solar PV Large (50 MW)	14.17	3,915,987	950	1,106	$0
2026	Reciprocating Engines (41 MW)	14.51	3,911,872	949	1,099	**Outside Adjustment 2**
2027	Aeroderivative (40 MW)	14.76	4,079,204	966	1,118	$0
2028	Large GT (187 MW)	14.76	4,034,363	957	1,110	**Outside Model Adjustment 3**
2029	Aeroderivative (40 MW)	14.84	4,051,271	952	1,102	$0
2030	Aeroderivative (40 MW)	14.88	4,133,781	967	1,110	**Outside Model Adjustment 4**
2031	Solar PV Large (50 MW)	14.16	3,834,822	892	1,014	$0
	Wind (100 MW)					**Total Optimized NPV + Adjustments**
2032	Large GT (187 MW)	20.12	3,882,383	900	1,020	$7,147,454,781
2033		18.36	4,006,192	915	1,034	**Average Risk NPV + Adjustments**
2034		17	3,980,030	909	1,029	$7,363,303,134
2035		15	4,037,084	907	1,030	
2036	Solar PV Large (100 MW)	14	4,088,961	914	1,027	

Table 94. 2017 IRP: SJGS Continues Beyond 2022 (LOAD = MID, GAS = HIGH, CO2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,360	1,302	1,682	$7,128,009,703
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,375,457	988	1,478	32.36
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,111,376	923	1,315	$7,145,098,367
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,865,593	858	1,171	$82,532,147
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,830,211	829	1,117	93,135,487
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,810,008	806	1,054	$28,645,975
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,424,108	933	1,119	946
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1158
2024		18.27	3,547,298	965	1,138	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,522,756	953	1,132	52.406
2026		15.97	3,488,777	952	1,124	**Outside Adjustment 1**
2027		14.72	3,635,772	970	1,147	$0
2028	Large GT (187 MW)	14.81	3,580,073	958	1,135	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,492,133	932	1,093	$0
2030	Reciprocating Engines (41 MW)	14.46	3,563,025	950	1,104	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,624,337	942	1,108	$0
2032	Large GT (187 MW)	20.37	3,682,179	951	1,116	**Outside Model Adjustment 4**
2033		18.34	3,830,203	970	1,132	$0
2034		16.46	3,816,664	964	1,127	**Total Optimized NPV + Adjustments**
2035	Wind (100 MW)	14.59	3,623,608	907	1,044	$7,128,009,703
2036	Aeroderivative (40 MW)	14.10	3,622,564	902	1,022	**Average Risk NPV + Adjustments**
	Wind (100 MW)					$7,145,098,367

Table 95. 2017 IRP: SJGS Continues Beyond 2022 - Solar Sensitivity Base - 50 MW Distribution, 2x50 MW and 1x100 MW Transmission Solar PV Available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,145,621,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	31.65
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,142,442,737
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,947,265
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,715,837
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,943,162
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1171
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.622
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Large GT (187 MW)	20.99	3,580,246	947	1,104	**Outside Model Adjustment 3**
2031		18.85	3,642,256	942	1,110	$0
2032		16.82	3,699,112	951	1,117	**Outside Model Adjustment 4**
2033		14.86	3,850,884	969	1,134	$0
2034	Reciprocating Engines (41 MW)	14.74	3,830,596	962	1,127	**Total Optimized NPV + Adjustments**
2035	Reciprocating Engines (41 MW)	14.39	3,910,751	961	1,128	$7,145,621,594
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,142,442,737

Table 96. 2017 IRP: SJGS Continues Beyond 2022 - Solar Sensitivity 0% Cost Escalation - 50 MW Distribution, 2x50 MW and 1x100 MW Transmission Solar PV Available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,143,405,844
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	31.88
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,140,264,226
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$84,304,785
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,319,648
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,076,613
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	948
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1164
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.416
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Large GT (187 MW)	20.99	3,580,246	947	1,104	**Outside Model Adjustment 3**
2031		18.85	3,642,256	942	1,110	$0
2032		16.82	3,699,112	951	1,117	**Outside Model Adjustment 4**
2033		14.86	3,850,884	969	1,134	$0
2034	Reciprocating Engines (41 MW)	14.74	3,830,596	962	1,127	**Total Optimized NPV + Adjustments**
2035	Solar PV Large (100 MW)	14.14	3,718,730	920	1,067	$7,143,405,844
2036	Reciprocating Engines (41 MW)	14.20	3,881,317	949	1,094	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,140,264,226

Table 97. 2017 IRP: SJGS Continues Beyond 2022 - Solar Sensitivity Declining Cost Curve - 50 MW Distribution, 2x50 MW and 1x100 MW Transmission Solar PV Available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,164,132,016
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	43.38
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,162,158,904
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$73,071,453
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	88,087,967
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$161,929,617
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.66	3,426,656	930	1,116	878
	Palo Verde Undepreciated Assets					**20-Year PNM NM CO2 (lbs/MWh)**
	Reciprocating Engines (82 MW)					1046
2024	Solar PV Transmission (50 MW) -2024 PRICING	14.07	3,454,513	938	1,099	**20-Year Freshwater (Bn of Gal)**
2025	Solar PV Transmission (100 MW) -2024 PRICING	14.58	3,277,592	887	1,030	49.880
2026	Aeroderivative (40 MW)	15.38	3,237,572	886	1,021	**Outside Adjustment 1**
2027		14.14	3,356,546	900	1,041	$0
2028	Large GT (187 MW)	14.24	3,336,981	893	1,035	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW) -2024 PRICING	14.51	3,183,041	849	965	$0
	Solar PV Transmission (50 MW) -2024 PRICING					**Outside Model Adjustment 3**
2030	Solar PV Transmission (100 MW) -2024 PRICING	14.42	3,134,258	831	921	$0
2031	Aeroderivative (40 MW)	14.16	3,211,783	828	932	**Outside Model Adjustment 4**
2032	Solar PV Transmission (50 MW) -2024 PRICING	14.47	3,151,162	794	872	$0
	Solar PV Transmission (100 MW) -2024 PRICING					**Total Optimized NPV + Adjustments**
2033	Aeroderivative (40 MW)	14.25	3,219,167	804	881	$7,164,132,016
2034	Rio Bravo CC Expansion (210 MW)	15.44	3,236,314	803	880	**Average Risk NPV + Adjustments**
2035	Solar PV Transmission (50 MW) -2024 PRICING	14	3,237,517	785	860	$7,162,158,904
2036	Large GT (187 MW)	19	3,412,996	824	904	

Table 98. 2017 IRP: SJGS Continues Beyond 2022 - Solar Sensitivity 0% Cost Escalation - 50 MW Distribution, 3x50 MW and 2x100 MW Transmission Solar PV Available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,144,517,797
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.33
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,141,430,898
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$84,198,420
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,478,414
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,417,373
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	950
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1166
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.545
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,144,517,797
2036		14.20	3,881,317	949	1,094	**Average Risk NPV + Adjustments**
						$7,141,430,898

Table 99. 2017 IRP: SJGS Continues Beyond 2022 -Wind Sensitivity Base (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,146,517,313
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,143,415,687
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,473,482
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,663
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,839,696
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,146,517,313
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,143,415,687

Table 100. 2017 IRP: SJGS Continues Beyond 2022 -New Wind pricing at $40/MWh (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,145,605,688
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	31.63
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,142,557,225
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$82,529,469
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,216,868
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$174,863,012
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	947
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1162
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.429
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,145,605,688
2036	Aeroderivative (40 MW)	14.10	3,632,162	899	1,021	**Average Risk NPV + Adjustments**
	Wind (200 MW)					$7,142,557,225

Table 101. 2017 IRP: SJGS Continues Beyond 2022 -New Wind pricing at $30/MWh (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,132,666,156
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	28.20
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,129,994,379
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$76,958,962
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	90,331,645
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$167,246,768
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	916
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1112
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	50.942
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Aeroderivative (40 MW)	15.53	3,327,723	891	1,034	$0
	Wind (100 MW)					**Outside Model Adjustment 3**
2030	Wind (100 MW)	14.08	3,137,001	850	955	$0
2031	Large GT (187 MW)	20.28	3,205,574	846	963	**Outside Model Adjustment 4**
2032		18.23	3,257,040	854	969	$0
2033		16.24	3,403,664	875	992	**Total Optimized NPV + Adjustments**
2034		14.39	3,398,960	870	987	$7,132,666,156
2035	Reciprocating Engines (41 MW)	14.04	3,462,366	869	991	**Average Risk NPV + Adjustments**
2036	Reciprocating Engines (41 MW)	14	3,632,162	899	1,021	$7,129,994,379
	Solar PV Distribution (50 MW)					

Table 102. 2017 IRP: SJGS Continues Beyond 2022 -New Wind pricing at $20/MWh (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,103,770,578
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	22.95
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,101,970,927
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$72,457,378
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	87,047,110
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$159,685,738
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.99	3,156,115	868	1,018	879
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1052
	Wind (100 MW)					**20-Year Freshwater (Bn of Gal)**
2024	Wind (100 MW)	18.75	3,018,641	838	942	49.268
2025		17.55	3,013,860	829	940	**Outside Adjustment 1**
2026		16.44	2,970,703	827	931	$0
2027		15.18	3,097,262	843	955	**Outside Adjustment 2**
2028	Large GT (187 MW)	15.27	3,077,378	836	947	$0
2029	Aeroderivative (40 MW)	15.76	3,068,047	832	942	**Outside Model Adjustment 3**
2030		14.08	3,137,001	850	955	$0
2031	Large GT (187 MW)	20.28	3,205,574	846	963	**Outside Model Adjustment 4**
2032		18.23	3,257,040	854	969	$0
2033		16.24	3,403,664	875	992	**Total Optimized NPV + Adjustments**
2034		14.39	3,398,960	870	987	$7,103,770,578
2035	Reciprocating Engines (41 MW)	14.04	3,462,366	869	991	**Average Risk NPV + Adjustments**
2036	Reciprocating Engines (41 MW)	14	3,632,162	899	1,021	$7,101,970,927
	Solar PV Distribution (50 MW)					

Table 103. 2017 IRP: SJGS Continues Beyond 2022 -New Wind pricing at $46.85/MWh, 100 MW Sizing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,146,517,313
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,143,415,687
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,473,482
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,663
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,839,696
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,146,517,313
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,143,415,687

Table 104. 2017 IRP: SJGS Continues Beyond 2022 -New Wind pricing at $46.85/MWh, 50 MW Sizing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,146,517,313
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,143,415,687
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,473,482
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,663
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,839,696
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,146,517,313
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,143,415,687

Table 105. 2017 IRP: SJGS Continues Beyond 2022 -New Wind pricing at $46.85/MWh, 150 MW Sizing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,146,517,313
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,143,415,687
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,473,482
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,663
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,839,696
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,146,517,313
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,143,415,687

Table 106. 2017 IRP: SJGS Continues Beyond 2022 -New Wind pricing at $46.85/MWh, 200 MW Sizing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,147,277,219
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.06
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,144,142,864
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,613,791
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,700,138
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,897,046
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.632
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Aeroderivative (40 MW)	14.20	3,637,020	941	1,108	$0
2032	Large GT (187 MW)	20.32	3,694,140	950	1,116	**Outside Model Adjustment 4**
2033		18.30	3,844,967	968	1,132	$0
2034		16.41	3,830,575	962	1,127	**Total Optimized NPV + Adjustments**
2035		14.35	3,916,019	962	1,130	$7,147,277,219
2036	Reciprocating Engines (41 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,144,142,864

Table 107. 2017 IRP: SJGS Continues Beyond 2022 - New Wind pricing at $46.85/MWh, 100 MW Sizing, 45% Capacity Factor (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,146,517,313
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,379,700	987	1,477	32.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,117,899	921	1,314	$7,143,415,687
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,868,846	857	1,171	$85,473,482
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,835,608	828	1,116	93,677,663
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.43	2,815,337	805	1,054	$175,839,696
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.75	3,433,484	931	1,118	952
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1170
2024		18.27	3,558,066	962	1,136	**20-Year Freshwater (Bn of Gal)**
2025		17.07	3,530,832	951	1,131	52.646
2026		15.97	3,497,393	950	1,123	**Outside Adjustment 1**
2027		14.72	3,646,457	967	1,146	$0
2028	Large GT (187 MW)	14.81	3,586,607	956	1,134	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.28	3,499,729	929	1,092	$0
2030	Reciprocating Engines (41 MW)	14.46	3,575,507	946	1,102	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.24	3,632,957	940	1,107	$0
2032	Large GT (187 MW)	20.37	3,690,147	949	1,114	**Outside Model Adjustment 4**
2033		18.34	3,840,416	967	1,131	$0
2034		16.46	3,825,937	961	1,125	**Total Optimized NPV + Adjustments**
2035		14.39	3,910,751	961	1,128	$7,146,517,313
2036	Aeroderivative (40 MW)	14.40	4,075,431	990	1,155	**Average Risk NPV + Adjustments**
	Solar PV Large (50 MW)					$7,143,415,687

Table 108. 2017 IRP: SJGS Continues Beyond 2022 - New Wind pricing at $46.85/MWh, 100 MW Sizing, New Wind = 25% Capacity Factor (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,105,623,344
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,384,155	988	1,479	41.21
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.27	3,174,747	936	1,342	$7,101,566,554
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	2,973,323	883	1,222	$94,133,257
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.06	2,987,795	865	1,187	97,198,201
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.24	2,998,145	850	1,139	$183,773,969
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.55	3,664,060	982	1,199	990
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1231
2024		18.08	3,783,870	1,012	1,215	**20-Year Freshwater (Bn of Gal)**
2025		16.88	3,755,569	1,001	1,210	54.360
2026		15.78	3,725,861	1,000	1,202	**Outside Adjustment 1**
2027		14.53	3,870,675	1,016	1,222	$0
2028	Large GT (187 MW)	14.63	3,807,778	1,005	1,211	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.10	3,717,581	977	1,166	$0
2030	Reciprocating Engines (41 MW)	14.29	3,795,447	993	1,175	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.07	3,851,913	987	1,179	$0
2032	Large GT (187 MW)	20.19	3,911,110	996	1,187	**Outside Model Adjustment 4**
2033		18.18	4,055,914	1,012	1,198	$0
2034		16.29	4,042,358	1,006	1,194	**Total Optimized NPV + Adjustments**
2035		14.22	4,132,389	1,005	1,195	$7,105,623,344
2036	Solar PV Large (50 MW)	14.04	4,087,700	991	1,157	**Average Risk NPV + Adjustments**
	Solar PV Large (100 MW)					$7,101,566,554

Table 109. 2017 IRP: SJGS Continues Beyond 2022 - New Wind pricing at $46.85/MWh, 100 MW Sizing, New Wind = 55% Capacity Factor (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,170,559,188
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,377,450	986	1,476	28.70
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.35	3,089,587	914	1,300	$7,167,898,473
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.23	2,817,585	844	1,145	$80,138,987
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.29	2,762,338	810	1,081	91,820,939
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.52	2,729,176	784	1,013	$171,662,407
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.84	3,319,093	906	1,077	932
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					1137
2024		18.37	3,444,273	937	1,097	**20-Year Freshwater (Bn of Gal)**
2025		17.17	3,419,630	925	1,091	51.722
2026		16.07	3,383,987	924	1,083	**Outside Adjustment 1**
2027		14.81	3,532,509	942	1,107	$0
2028	Large GT (187 MW)	14.90	3,477,729	931	1,095	**Outside Adjustment 2**
2029	Solar PV Distribution (50 MW)	14.37	3,391,140	905	1,054	$0
2030	Reciprocating Engines (41 MW)	14.55	3,464,540	922	1,065	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.33	3,524,151	916	1,071	$0
2032	Aeroderivative (40 MW)	14.10	3,580,022	925	1,078	**Outside Model Adjustment 4**
2033	Large GT (187 MW)	20.13	3,730,018	944	1,096	$0
2034		18.21	3,717,320	938	1,090	**Total Optimized NPV + Adjustments**
2035		16.11	3,798,113	938	1,094	$7,170,559,188
2036	Solar PV Large (50 MW)	14.48	3,967,502	968	1,123	**Average Risk NPV + Adjustments**
						$7,167,898,473

Table 110. 2017 IRP: SJGS Continues Beyond 2022 - New Wind pricing at $20/MWh, 200 MW Sizing, New Wind = 55% Capacity Factor (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,121,478,984
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,377,450	986	1,476	19.58
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.35	3,089,587	914	1,300	$7,120,209,321
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.23	2,817,585	844	1,145	$69,797,431
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.29	2,762,338	810	1,081	82,690,939
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.52	2,729,176	784	1,013	$149,135,663
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	19.84	3,319,093	906	1,077	826
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					965
2024		18.37	3,444,273	937	1,097	**20-Year Freshwater (Bn of Gal)**
2025	Wind (200 MW)	17.75	2,826,518	782	866	47.040
2026		16.64	2,781,447	780	856	**Outside Adjustment 1**
2027		15.38	2,888,418	793	878	$0
2028	Large GT (187 MW)	15.47	2,889,439	790	873	**Outside Adjustment 2**
2029		14.14	2,865,398	784	867	$0
2030	Reciprocating Engines (41 MW)	14.32	2,923,085	800	878	**Outside Model Adjustment 3**
2031	Reciprocating Engines (41 MW)	14.10	2,995,888	797	888	$0
2032	Large GT (187 MW)	20.23	3,044,596	805	894	**Outside Model Adjustment 4**
2033	Wind (200 MW)	18.73	2,643,139	698	727	$0
2034		16.84	2,690,287	702	732	**Total Optimized NPV + Adjustments**
2035		14.76	2,696,957	696	732	$7,121,478,984
2036	Aeroderivative (40 MW)	14.06	2,902,846	741	786	**Average Risk NPV + Adjustments**
						$7,120,209,321

Table 111. 2017 IRP: SJGS Continues Beyond 2022 - Data Center2 Resources Included (LOAD = HIGH, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO_2 Tons1	PNM CPP CO_2 lbs/MWh1	PNM NM CPP CO_2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$8,005,475,797
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,428,305	996	1,492	26.94
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.30	3,130,333	966	1,438	$8,003,436,978
	Data Center2 Solar1 (150 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$89,380,945
2020	Data Center1 Solar3 (30 MW)	16.07	2,760,007	892	1,287	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					90,661,596
	Data Center2 Solar2 (150 MW)					**20-Year CO2 Cost (NPV)**
2021	Data Center1 Solar4 (30 MW)	18.16	2,792,482	866	1,225	$168,774,655
	Data Center1 Wind3 (50 MW)					**20-Year PNM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	15.85	2,677,611	835	1,151	980
	Data Center1 Wind4 (30 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Data Center2 Wind1 (200 MW)					1242
	Data Center2 Wind2 (100 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Data Center1 Solar6 (20 MW)	16.96	3,069,505	947	1,180	50.466
	Large GT (187 MW)					**Outside Adjustment 1**
	Data Center2 Wind3 (100 MW)					$0
	Palo Verde Undepreciated Assets					**Outside Adjustment 2**
2024	Large GT (187 MW)	21.67	3,107,513	971	1,187	$0
2025		19.44	3,188,041	968	1,192	**Outside Model Adjustment 3**
2026		17.85	3,185,366	969	1,186	$0
2027		16.16	3,308,223	985	1,204	**Outside Model Adjustment 4**
2028	Large GT (187 MW)	15.66	3,357,670	982	1,202	$0
2029	Solar PV Distribution (50 MW)	14.63	3,297,753	955	1,155	**Total Optimized NPV + Adjustments**
2030	Reciprocating Engines (41 MW)	14.23	3,383,410	973	1,163	$8,005,475,797
2031	Large GT (187 MW)	19.00	3,500,574	971	1,174	**Average Risk NPV + Adjustments**
2032		17	3,587,754	982	1,183	$8,003,436,978
2033		15	3,721,720	998	1,193	
2034	Large GT (187 MW)	19	3,792,822	998	1,194	
2035		17	3,869,073	994	1,191	
2036		14	4,151,888	1,046	1,251	

Table 112. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = LOW, GAS = LOW, CO2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$5,912,073,797
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,256,735	978	1,482	8.35
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,786,239	883	1,278	$5,909,254,807
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,598,976	829	1,150	$52,534,401
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,505,585	793	1,085	45,352,511
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,940,595	679	855	$10,426,205
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	16.19	787,891	435	316	537
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					581
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (41 MW)					23.423
2024	PVNGS U2 Lease Purchase (10 MW)	16.06	723,632	431	287	**Outside Adjustment 1**
2025		15.61	707,562	424	287	$0
2026		15.24	680,876	429	282	**Outside Adjustment 2**
2027		14.65	654,053	415	268	$0
2028	Large GT (187 MW)	15.61	627,927	417	263	**Outside Model Adjustment 3**
2029		14.93	639,796	417	270	$0
2030	Reciprocating Engines (41 MW)	15.99	597,265	415	251	**Outside Model Adjustment 4**
2031		14.39	610,589	408	258	$0
2032	Aeroderivative (40 MW)	14.27	1,102,209	273	386	**Total Optimized NPV + Adjustments**
	Four Corners Undepreciated Assets					$5,912,073,797
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
2033	Aeroderivative (40 MW)	15	1,091,251	271	378	$5,909,254,807
2034	Solar PV Large (50 MW)	14	1,032,612	255	360	
2035	Aeroderivative (40 MW)	15	1,057,713	261	369	
2036	Solar PV Large (100 MW)	14	1,021,925	251	350	
2036		14	4,151,888	1,046	1,251	

Table 113. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = LOW, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$6,200,277,438
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,253,464	979	1,483	8.00
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,778,060	885	1,280	$6,198,490,336
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,587,131	832	1,152	$97,409,659
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,495,425	795	1,086	44,615,948
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,926,309	685	857	$58,445,331
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	16.19	742,813	446	304	527
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					552
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (41 MW)					23.460
2024	PVNGS U2 Lease Purchase (10 MW)	16.06	680,722	441	275	**Outside Adjustment 1**
2025		15.61	661,757	435	274	$0
2026		15.24	633,614	440	268	**Outside Adjustment 2**
2027		14.65	614,065	425	256	$0
2028	Large GT (187 MW)	15.61	587,500	427	251	**Outside Model Adjustment 3**
2029		14.93	597,157	428	257	$0
2030	Reciprocating Engines (41 MW)	15.99	555,096	426	237	**Outside Model Adjustment 4**
2031		14.39	568,441	418	245	$0
2032	Aeroderivative (40 MW)	14.53	926,327	229	323	**Total Optimized NPV + Adjustments**
	Four Corners Undepreciated Assets					$6,200,277,438
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
	Wind (100 MW)					$6,198,490,336
2033	Aeroderivative (40 MW)	15	913,974	226	315	
2034	Wind (100 MW)	14	756,506	185	261	
2035	Aeroderivative (40 MW)	14	776,044	190	267	
2036	Solar PV Large (50 MW)	14	743,974	181	251	
	Solar PV Distribution (50 MW)					

Table 114. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = LOW, GAS = HIGH, CO2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,212	1,301	1,682	$6,449,045,656
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,249,282	980	1,484	7.34
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,772,693	887	1,280	$6,450,097,752
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,584,543	833	1,152	$126,355,736
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,492,456	796	1,086	42,790,511
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,917,470	687	856	$102,508,862
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.22	590,429	410	239	500
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					503
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Wind (100 MW)					22.945
2024	PVNGS U2 Lease Purchase (10 MW)	14.09	540,832	407	215	**Outside Adjustment 1**
2025	Reciprocating Engines (41 MW)	15.88	516,248	400	210	$0
2026		15.51	491,946	405	204	**Outside Adjustment 2**
2027		14.92	475,262	389	194	$0
2028	Large GT (187 MW)	15.88	456,674	393	190	**Outside Model Adjustment 3**
2029		15.20	460,487	393	193	$0
2030		14.09	430,191	392	179	**Outside Model Adjustment 4**
2031	Reciprocating Engines (41 MW)	14.65	439,874	383	185	$0
2032	Four Corners Undepreciated Assets	14.53	681,377	165	230	**Total Optimized NPV + Adjustments**
	Large GT (187 MW)					$6,449,045,656
	Solar PV Large (50 MW)					**Average Risk NPV + Adjustments**
	Solar PV Distribution (50 MW)					$6,450,097,752
	Wind (100 MW)					
2033	Aeroderivative (40 MW)	15	671,212	162	224	
2034	Solar PV Large (50 MW)	15	642,354	154	214	
2035	Aeroderivative (40 MW)	15	657,480	158	220	
2036	Aeroderivative (40 MW)	15	711,121	171	237	

Table 115. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = LOW, GAS = MID, CO2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.65	4,789,274	1,301	1,682	$6,133,348,813
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	22.13	3,253,464	979	1,483	8.40
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	25.88	2,778,060	885	1,280	$6,131,484,222
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	27.22	2,587,131	832	1,152	$102,084,751
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	27.92	2,495,425	795	1,086	45,393,850
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	30.03	1,926,104	685	857	$0
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	16.19	740,258	446	304	536
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					567
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (41 MW)					23.637
2024	PVNGS U2 Lease Purchase (10 MW)	16.06	678,075	442	275	**Outside Adjustment 1**
2025		15.61	660,779	435	273	$0
2026		15.24	633,148	440	268	**Outside Adjustment 2**
2027		14.65	611,627	425	255	$0
2028	Large GT (187 MW)	15.61	585,633	427	250	**Outside Model Adjustment 3**
2029		14.93	595,616	428	256	$0
2030	Reciprocating Engines (41 MW)	15.99	553,162	426	237	**Outside Model Adjustment 4**
2031		14.39	566,453	419	245	$0
2032	Four Corners Undepreciated Assets	14.02	989,214	244	343	**Total Optimized NPV + Adjustments**
	Large GT (187 MW)					$6,133,348,813
	Solar PV Large (50 MW)					**Average Risk NPV + Adjustments**
	Solar PV Distribution (50 MW)					$6,131,484,222
2033	Aeroderivative (40 MW)	15	977,859	241	336	
2034	Solar PV Large (50 MW)	14	931,932	228	321	
2035	Aeroderivative (40 MW)	14	955,262	234	329	
2036	Aeroderivative (40 MW)	14	1,021,959	251	350	

Table 116. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = MID, GAS = LOW, CO2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,427,919,734
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,422,782	993	1,487	17.74
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,086,454	912	1,299	$6,427,417,593
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,928,001	861	1,182	$100,336,514
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,928,592	837	1,136	59,231,122
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,429,765	727	917	$15,422,364
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,347,051	503	442	605
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					674
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.937
2024	Aeroderivative (40 MW)	15.37	1,315,402	504	424	**Outside Adjustment 1**
	PVNGS U2 Lease Purchase (10 MW)					$0
2025		14.19	1,341,133	501	433	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.00	1,365,867	513	441	$0
2027	Aeroderivative (40 MW)	15.62	1,372,602	506	435	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	15.70	1,372,374	509	438	$0
2029		14.37	1,443,120	517	454	**Outside Model Adjustment 4**
2030	Large GT (187 MW)	21.11	1,443,266	521	448	$0
2031		18.96	1,514,632	520	465	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16.35	2,216,198	437	570	$6,427,919,734
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
2033		14	2,273,221	444	572	$6,427,417,593
2034	Solar PV Large (50 MW)	14	2,159,596	418	541	
	Solar PV Distribution (50 MW)					
2035	Solar PV Large (50 MW)	14	2,034,596	389	502	
	Solar PV Large (100 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	2,020,301	383	489	

Table 117. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included (U1 & U2) (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,997,576,344
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.16
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$7,007,311,589
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$156,844,314
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	58,217,357
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$88,469,777
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	591
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					576
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					28.891
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,997,576,344
2032		16.70	1,088,219	449	330	**Average Risk NPV + Adjustments**
2033	Wind (100 MW)	15	970,886	414	284	$7,007,311,589
2034	Aeroderivative (40 MW)	15	1,001,607	423	293	
2035	Aeroderivative (40 MW)	14	1,082,947	427	311	
2036	Rio Bravo CC Expansion (210 MW)	15	1,120,915	437	318	

Table 118. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases not available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,982,684,359
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	16.55
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,992,040,928
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$184,746,914
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	61,884,891
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$97,203,172
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Aeroderivatives (80 MW)	14.07	1,619,630	583	543	629
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					638
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					29.402
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
2024	Solar PV Large (100 MW)	14.33	1,556,513	576	511	$0
2025	Solar PV Large (50 MW)	14.24	1,290,574	511	421	**Outside Adjustment 2**
	Wind (100 MW)					$0
2026	Aeroderivative (40 MW)	15.05	1,287,469	517	420	**Outside Model Adjustment 3**
2027	Wind (100 MW)	14.03	1,183,638	480	376	$0
2028	Large GT (187 MW)	14.14	1,162,792	479	370	**Outside Model Adjustment 4**
2029	Large GT (187 MW)	21.34	1,195,492	480	377	$0
2030		19.58	1,245,235	495	388	**Total Optimized NPV + Adjustments**
2031		17.46	1,284,033	488	396	$6,982,684,359
2032		15.44	1,297,019	494	397	**Average Risk NPV + Adjustments**
2033	Solar PV Large (50 MW)	14	1,344,569	494	399	$6,992,040,928
2034	Large GT (187 MW)	20	1,350,810	497	400	
2035		18	1,418,254	497	413	
2036		16	1,581,959	532	454	

Table 119. 2017 IRP: SJGS Retires in 2022 - PVNGS Low Fuel and O&M (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,793,374,641
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,804,062,552
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,811
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,793,374,641
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,804,062,552
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 120. 2017 IRP: SJGS Retires in 2022 - PVNGS High Fuel and O&M (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,065,005,016
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$7,075,692,978
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,834
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$7,065,005,016
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$7,075,692,978
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 121. 2017 IRP: SJGS Retires in 2022 - PVNGS Leases included, FCPP Exit in 2031, Electric Market (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	6,487,258	1,360	1,658	$6,757,740,031
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	4,883,426	1,085	1,485	1.83
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	4,628,629	1,026	1,361	$6,660,563,666
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	4,739,965	1,012	1,312	$139,408,101
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	4,811,991	998	1,288	67,174,009
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	3,767,484	871	1,095	$90,052,334
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,323,641	522	444	633
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					694
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					31.264
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,257,315	512	408	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,242,854	492	390	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,209,739	498	387	$0
2027		14.34	1,215,216	487	382	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,367,160	510	416	$0
2029	Solar PV Large (50 MW)	14.14	1,315,262	477	377	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	1,312,723	481	371	**Total Optimized NPV + Adjustments**
2031		18.74	1,392,585	482	390	$6,757,740,031
2032	Four Corners Undepreciated Assets	16.35	1,572,684	309	403	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,660,563,666
	Wind (100 MW)					
2033		14	1,559,672	307	396	
2034	Aeroderivative (40 MW)	14	1,648,157	319	413	
2035	Aeroderivative (40 MW)	15	1,636,429	315	407	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,943,180	351	443	

Table 122. 2017 IRP: SJGS Retires in 2022 - FCPP Exit in 2031 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,949,096,531
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.40
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,959,558,723
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$176,054,218
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	55,101,488
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$81,046,954
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.09	1,189,627	489	395	560
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					594
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (41 MW)					26.261
	Solar PV Large (100 MW)					**Outside Adjustment 1**
2024	Reciprocating Engines (41 MW)	14.64	1,184,062	495	386	$0
2025	Solar PV Distribution (50 MW)	14.31	1,142,426	480	372	**Outside Adjustment 2**
2026	Solar PV Large (50 MW)	14.06	1,111,915	477	360	$0
2027	Aeroderivative (40 MW)	14.69	1,128,211	468	358	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.78	1,131,508	474	361	$0
2029	Solar PV Large (50 MW)	14.25	1,143,214	468	359	**Outside Model Adjustment 4**
2030	Large GT (187 MW)	21.00	1,143,592	472	354	$0
2031	Wind (100 MW)	19.07	1,043,667	435	317	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16.68	1,500,488	294	383	$6,949,096,531
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
	Wind (100 MW)					$6,959,558,723
2033		15	1,543,669	300	386	
2034	Aeroderivative (40 MW)	15	1,595,833	307	397	
2035	Aeroderivative (40 MW)	14	1,670,916	319	411	
2036	Rio Bravo CC Expansion (210 MW)	15	1,677,295	317	405	

Table 123. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - No Renewable Integration Costs (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,941,727,703
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	16.90
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,939,881,397
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$143,426,595
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,443,061
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$79,130,924
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	553
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					584
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.159
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Aeroderivative (40 MW)	15.02	1,214,309	498	399	**Outside Adjustment 2**
2026	Wind (100 MW)	14.17	1,059,874	469	346	$0
2027	Solar PV Large (100 MW)	14.57	975,550	435	308	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.67	979,310	440	311	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
2030	Large GT (187 MW)	20.89	992,444	439	305	$0
2031	Wind (100 MW)	18.96	898,757	403	271	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	$6,941,727,703
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
2033		14	1,563,348	304	392	$6,939,881,397
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,687	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 124. 2017 IRP: SJGS Retires in 2022 - No Demand Response (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,946,832,547
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	15.16	3,418,566	994	1,488	18.14
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	15.83	3,075,947	914	1,300	$7,033,210,624
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	15.65	2,912,794	864	1,183	$170,395,750
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	14.66	2,913,194	840	1,137	54,245,020
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	14.33	2,417,581	736	922	$79,134,927
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.31	1,116,134	471	369	551
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					581
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					27.720
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
	Solar PV Large (100 MW)					$0
2024	PVNGS U2 Lease Purchase (10 MW)	14.14	1,044,807	460	335	**Outside Adjustment 2**
	Solar PV Large (50 MW)					$0
2025	Large GT (187 MW)	21.83	1,057,046	459	341	**Outside Model Adjustment 3**
2026		20.61	1,077,752	470	348	$0
2027		19.23	1,093,958	461	346	**Outside Model Adjustment 4**
2028	Large GT (187 MW)	19.26	1,094,646	465	349	$0
2029		17.88	1,155,645	472	365	**Total Optimized NPV + Adjustments**
2030		16.17	1,155,329	476	359	$6,946,832,547
2031	Wind (100 MW)	14.32	1,050,173	438	321	**Average Risk NPV + Adjustments**
2032	1x1 NGCC (250 MW)	15	1,422,463	279	364	$7,033,210,624
	Four Corners Undepreciated Assets					
	Wind (100 MW)					
2033	Aeroderivative (40 MW)	15	1,455,592	283	365	
2034	Aeroderivative (40 MW)	14	1,504,699	290	375	
2035	Aeroderivative (40 MW)	15	1,516,581	289	373	
	Solar PV Large (50 MW)					
2036	Large GT (187 MW)	20	1,630,615	308	394	

Table 125. 2017 IRP: SJGS Retires in 2022 - 2017 IRP Low EE Forecast (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.28	4,822,956	1,302	1,682	$6,982,079,281
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.55	3,423,771	994	1,488	17.76
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.23	3,084,366	915	1,301	$6,993,311,385
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.03	2,924,867	865	1,184	$169,082,087
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.01	2,930,745	842	1,139	55,024,933
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.64	2,438,834	738	925	$80,629,049
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.02	1,320,731	516	438	555
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					585
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.422
2024	PVNGS U2 Lease Purchase (10 MW)	14.68	1,174,263	490	379	**Outside Adjustment 1**
	Solar PV Large (100 MW)					$0
2025	Solar PV Distribution (50 MW)	14.26	1,134,448	475	365	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	14.98	1,160,900	486	374	$0
2027	Solar PV Large (50 MW)	14.45	1,134,712	466	355	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.46	1,139,823	471	358	$0
2029	Solar PV Large (50 MW)	14.05	998,896	429	305	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.66	1,005,085	434	301	**Total Optimized NPV + Adjustments**
2031		18.49	1,064,376	434	317	$6,982,079,281
2032	Four Corners Undepreciated Assets	16.10	1,530,656	296	384	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,993,311,385
	Wind (100 MW)					
2033		14	1,577,091	302	388	
2034	Rio Bravo CC Expansion (210 MW)	15	1,521,833	289	372	
2035	Aeroderivative (40 MW)	15	1,594,227	300	385	
2036	Aeroderivative (40 MW)	14	1,714,523	320	407	

Table 126. 2017 IRP: SJGS Retires in 2022 - 2017 IRP High EE Forecast (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,419	1,302	1,682	$6,926,975,266
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.60	3,419,220	994	1,488	16.98
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.33	3,075,774	914	1,300	$6,951,197,580
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.19	2,911,084	864	1,183	$169,262,616
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.25	2,909,534	840	1,136	53,808,773
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.99	2,411,838	735	921	$77,555,016
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.51	1,289,591	513	432	550
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					580
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.082
2024	PVNGS U2 Lease Purchase (10 MW)	14.46	1,187,416	498	389	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (50 MW)	14.19	1,141,355	482	375	**Outside Adjustment 2**
2026	Solar PV Large (50 MW)	14.02	1,105,787	480	362	$0
2027	Aeroderivative (40 MW)	14.73	1,118,168	470	359	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	15.14	952,017	436	305	$0
	Wind (100 MW)					**Outside Model Adjustment 4**
2029	Wind (100 MW)	14.16	850,999	406	267	$0
2030	Large GT (187 MW)	21.05	847,539	410	262	**Total Optimized NPV + Adjustments**
2031		18.96	896,548	408	276	$6,926,975,266
2032	Four Corners Undepreciated Assets	16.42	1,519,744	302	395	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,951,197,580
2033		15	1,558,534	308	398	
2034	Solar PV Large (100 MW)	14	1,482,584	289	375	
2035	Rio Bravo CC Expansion (210 MW)	15	1,455,269	281	364	
2036	Aeroderivative (40 MW)	15	1,564,706	300	385	

Table 127. 2017 IRP: SJGS Retires in 2022 - No Demand Response or EE beginning 2018 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	24.76	4,972,419	1,310	1,682	$7,105,650,875
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	2nd Aeroderivative (40 MW)	15.06	3,626,477	1,011	1,493	20.70
	Data Center1 Solar1 (30 MW)					**Risk Porfolio Average (NPV)**
	Data Center1 Wind1 (50 MW)					$7,294,416,268
2019	Data Center1 Solar2 (40 MW)	14.85	3,371,013	942	1,325	**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$172,701,348
2020	Data Center1 Solar3 (30 MW)	14.04	3,288,664	905	1,231	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					60,606,965
2021	Data Center1 Solar4 (30 MW)	14.33	3,361,458	889	1,194	**20-Year CO2 Cost (NPV)**
	Data Center1 Wind3 (50 MW)					$90,808,724
	Reciprocating Engines (41 MW)					**20-Year PNM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	14.16	2,795,379	767	955	572
	Data Center1 Wind4 (30 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Solar PV Distribution (50 MW)					607
2023	Aeroderivative (40 MW)	14.18	1,368,130	487	402	**20-Year Freshwater (Bn of Gal)**
	Data Center1 Solar6 (20 MW)					30.213
	2 x Large GT (374 MW)					**Outside Adjustment 1**
	Palo Verde Undepreciated Assets					$0
	PVNGS U1 Lease Purchase (104 MW)					**Outside Adjustment 2**
	Reciprocating Engines (41 MW)					$0
	Solar PV Large (100 MW)					**Outside Model Adjustment 3**
	Solar PV Large (100 MW)					$0
2024	Large GT (187 MW)	21.25	1,372,666	492	393	**Outside Model Adjustment 4**
	PVNGS U2 Lease Purchase (10 MW)					$0
2025		19.63	1,411,112	493	403	**Total Optimized NPV + Adjustments**
2026		18.01	1,461,182	506	415	$7,105,650,875
2027	Wind (100 MW)	16.60	1,320,400	463	364	**Average Risk NPV + Adjustments**
2028	Large GT (187 MW)	17	1,325,810	468	367	$7,294,416,268
2029		15	1,396,946	475	382	
2030	Large GT (187 MW)	21	1,227,136	444	328	
	Wind (100 MW)					
2031		20	1,285,414	443	342	
2032	1x1 NGCC (250 MW)	20	1,822,477	327	415	
	Four Corners Undepreciated Assets					
2033		18	1,849,646	330	415	
2034		16	1,886,640	334	423	
2035		15	1,947,566	343	432	
2036	Aeroderivative (40 MW)	14	2,060,896	360	451	

Table 128. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 129. 2017 IRP: SJGS Retires in 2022 - FCPP Exit in 2031, No PVNGS Leases available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,951,746,203
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	18.22
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,961,349,919
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$219,685,073
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	59,490,555
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$91,125,796
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	1x1 NGCC (250 MW)	17.50	1,608,215	579	538	607
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					666
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
2024		16.04	1,659,741	598	546	31.858
2025		14.86	1,647,588	592	545	**Outside Adjustment 1**
2026	Solar PV Distribution (50 MW)	14.60	1,577,442	582	521	$0
2027	Solar PV Large (50 MW)	14.17	1,585,729	569	511	**Outside Adjustment 2**
2028	Large GT (187 MW)	14.51	1,375,580	529	446	$0
	Wind (100 MW)					**Outside Model Adjustment 3**
2029	Solar PV Large (50 MW)	14.21	1,192,697	481	378	$0
	Wind (100 MW)					**Outside Model Adjustment 4**
2030	Solar PV Large (100 MW)	14.12	1,141,375	470	353	$0
2031	Large GT (187 MW)	20.35	1,177,915	463	360	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	17.72	1,777,770	350	456	$6,951,746,203
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
2033		16	1,872,173	365	470	$6,961,349,919
2034	Reciprocating Engines (41 MW)	16	1,878,046	363	470	
2035	Reciprocating Engines (41 MW)	15	1,916,606	367	473	
2036	Aeroderivative (40 MW)	15	2,096,198	397	508	

Table 130. 2017 IRP: SJGS Retires in 2022 - FCPP Exit in 2031, PVNGS Leases Included, No EE (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	24.76	4,972,419	1,310	1,682	$7,028,944,125
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	15.40	3,613,835	1,008	1,488	29.28
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	15.26	3,341,364	936	1,313	$7,214,607,986
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	14.51	3,245,601	895	1,213	$174,904,091
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	14.86	3,362,411	889	1,195	60,735,209
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
	Reciprocating Engines (41 MW)					$91,219,465
2022	Data Center1 Solar5 (40 MW)	14.75	2,796,329	767	955	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind4 (30 MW)					574
	Solar PV Distribution (50 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2023	Aeroderivative (40 MW)	14.01	1,423,972	499	420	610
	Data Center1 Solar6 (20 MW)					**20-Year Freshwater (Bn of Gal)**
	2 x Large GT (374 MW)					30.225
	Palo Verde Undepreciated Assets					**Outside Adjustment 1**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Reciprocating Engines (41 MW)					**Outside Adjustment 2**
	Solar PV Large (50 MW)					$0
	Solar PV Large (100 MW)					**Outside Model Adjustment 3**
2024	Large GT (187 MW)	21.15	1,426,831	504	411	$0
	PVNGS U2 Lease Purchase (10 MW)					**Outside Model Adjustment 4**
2025		19.61	1,467,115	505	421	$0
2026		18.05	1,518,318	518	433	**Total Optimized NPV + Adjustments**
2027	Wind (100 MW)	16.71	1,373,528	475	380	$7,028,944,125
2028	Large GT (187 MW)	16.68	1,377,637	479	383	**Average Risk NPV + Adjustments**
2029	Wind (100 MW)	15	1,272,490	451	347	$7,214,607,986
2030	Solar PV Large (50 MW)	14	1,226,905	444	328	
2031	Aeroderivative (40 MW)	14	1,285,176	443	342	
2032	1x1 NGCC (250 MW)	15	1,821,993	327	415	
	Four Corners Undepreciated Assets					
2033	Large GT (187 MW)	21	1,849,111	330	415	
2034		19	1,886,162	334	423	
2035		17	1,947,042	343	432	
2036		15	2,060,380	360	451	

Table 131. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031- Battery Sensitivity - 2hr, 2MW battery available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,109,063
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.31
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,966,669,171
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$182,164,172
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	55,481,781
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$81,912,614
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	565
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					602
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.423
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Aeroderivative (40 MW)	15.02	1,214,309	498	399	**Outside Adjustment 2**
2026	2-Hr Battery (2 MW)	14.03	1,235,547	509	406	$0
2027	Solar PV Large (100 MW)	14.43	1,141,778	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.53	1,141,254	477	366	$0
2029	Solar PV Large (50 MW)	14.00	1,154,300	472	364	**Outside Model Adjustment 4**
2030	Large GT (187 MW)	20.75	1,153,737	476	359	$0
2031	Wind (100 MW)	18.83	1,048,323	438	320	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16.44	1,517,622	298	388	$6,956,109,063
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
	Wind (100 MW)					$6,966,669,171
2033		14	1,562,472	304	392	
2034	Aeroderivative (40 MW)	14	1,611,877	311	402	
2035	Aeroderivative (40 MW)	15	1,629,646	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,639,900	310	396	

Table 132. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Exit in 2031 - Battery Sensitivity - 4hr, 40 MW battery available (LOAD = MID, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO_2 Tons1	PNM CPP CO_2 lbs/MWh1	PNM NM CPP CO_2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO_2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO_2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO_2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO_2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	
	Wind (100 MW)					**Outside Model Adjustment 4**
2030	Large GT (187 MW)	20.89	992,444	439	305	$0
2031		18.74	1,049,826	438	320	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	$6,956,827,594
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
	Wind (100 MW)					$6,967,515,573
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 133. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - Battery Sensitivity - 2hr, 2MW battery included in 2023 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,720,250
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.29
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,298,242
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$182,176,617
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	55,479,740
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$81,908,526
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	2-Hr Battery (2 MW)	14.48	1,297,386	514	433	565
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					602
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					26.424
	Reciprocating Engines (82 MW)					**Outside Adjustment 1**
2024	PVNGS U2 Lease Purchase (10 MW)	14.38	1,198,319	499	392	$0
	Solar PV Distribution (50 MW)					**Outside Adjustment 2**
2025	Aeroderivative (40 MW)	15.12	1,213,513	498	398	$0
2026		14.03	1,235,547	509	406	**Outside Model Adjustment 3**
2027	Solar PV Large (100 MW)	14.43	1,141,778	473	364	$0
2028	Large GT (187 MW)	14.53	1,141,254	477	366	**Outside Model Adjustment 4**
2029	Solar PV Large (50 MW)	14.00	1,154,300	472	364	$0
2030	Large GT (187 MW)	20.75	1,153,737	476	359	**Total Optimized NPV + Adjustments**
2031	Wind (100 MW)	18.83	1,048,323	438	320	$6,956,720,250
2032	Four Corners Undepreciated Assets	16.44	1,517,622	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,298,242
	Wind (100 MW)					
2033		14	1,562,472	304	392	
2034	Aeroderivative (40 MW)	14	1,611,877	311	402	
2035	Aeroderivative (40 MW)	15	1,629,646	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,639,900	310	396	

Table 134. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Exit in 2031 - Battery Sensitivity - 4hr, 40 MW battery included in 2023 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,990,859,344
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.12
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$7,001,592,055
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$172,495,968
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,707,627
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$79,929,615
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	4-Hr Battery (40 MW)	14.34	1,302,896	514	435	557
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					589
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					26.299
	Reciprocating Engines (41 MW)					**Outside Adjustment 1**
2024	PVNGS U2 Lease Purchase (10 MW)	14.23	1,199,425	500	392	$0
	Solar PV Distribution (50 MW)					**Outside Adjustment 2**
2025	Solar PV Large (100 MW)	14.74	1,095,579	471	357	$0
2026	Reciprocating Engines (41 MW)	15.59	1,106,078	479	361	**Outside Model Adjustment 3**
2027		14.34	1,123,775	470	359	$0
2028	Large GT (187 MW)	14.44	1,122,959	475	362	**Outside Model Adjustment 4**
2029	Solar PV Large (50 MW)	14.14	967,289	431	303	$0
	Wind (100 MW)					**Total Optimized NPV + Adjustments**
2030	Large GT (187 MW)	20.89	965,543	435	298	$6,990,859,344
2031		18.74	1,025,059	435	314	**Average Risk NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16	1,502,552	295	384	$7,001,592,055
	Large GT (187 MW)					
	Wind (100 MW)					
2033		14	1,548,064	302	388	
2034	Aeroderivative (40 MW)	14	1,598,137	308	399	
2035	Aeroderivative (40 MW)	15	1,613,324	308	397	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,630,286	308	394	

Table 135. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - Battery Sensitivity - (2) x 2hr, 2MW battery available (LOAD = MID, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO_2 Tons1	PNM CPP CO_2 lbs/MWh1	PNM NM CPP CO_2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,538,750
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.14
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,224,170
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$175,658,292
	Data Center1 Wind2 (50 MW)					**20-Year CO_2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	55,024,394
	Data Center1 Wind3 (50 MW)					**20-Year CO_2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,706,333
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO_2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	560
	2 x Large GT (374 MW)					**20-Year PNM NM CO_2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					594
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.301
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,538,750
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,224,170
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	14	1,690,358	323	417	
	(2) x 2-Hr Battery (4 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,699,651	322	411	

Table 136. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - Battery Sensitivity - (3) x 2hr, 2MW battery available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,750,375
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.13
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,438,308
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$175,667,531
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	55,023,032
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,703,326
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	560
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					594
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.301
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,750,375
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,438,308
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	14	1,689,464	323	416	
	(3) x 2-Hr Battery (6 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,699,182	322	411	

Table 137. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - Battery Sensitivity - (4) x 2hr, 2MW battery available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 138. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - Solar Power Tower Available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 139. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Exit in 2031 - PA Scenario (LOAD = MID, GAS = HIGH, CO2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,360	1,302	1,682	$7,237,033,391
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,415,016	995	1,489	16.35
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,069,838	915	1,301	$7,254,676,877
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,910,535	865	1,183	$226,259,538
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,910,054	841	1,137	52,428,107
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,409,686	738	922	$12,770,779
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.34	995,356	453	330	530
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					546
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (41 MW)					25.638
	Solar PV Large (100 MW)					**Outside Adjustment 1**
	Wind (100 MW)					$0
2024	PVNGS U2 Lease Purchase (10 MW)	14.47	776,644	404	245	**Outside Adjustment 2**
	Solar PV Distribution (50 MW)					$0
	Wind (100 MW)					**Outside Model Adjustment 3**
2025	Reciprocating Engines (41 MW)	15.26	782,171	401	249	$0
2026		14.17	800,336	412	255	**Outside Model Adjustment 4**
2027	Aeroderivative (40 MW)	14.80	810,183	403	253	$0
2028	Large GT (187 MW)	14.90	819,433	409	258	**Total Optimized NPV + Adjustments**
2029	Solar PV Large (50 MW)	14.37	830,858	404	257	$7,237,033,391
2030	Large GT (187 MW)	21.11	832,628	408	253	**Average Risk NPV + Adjustments**
2031		19	886,296	407	268	$7,254,676,877
2032	Four Corners Undepreciated Assets	17	1,472,186	288	375	
	Large GT (187 MW)					
	Solar PV Large (50 MW)					
2033		15	1,516,703	295	379	
2034	Aeroderivative (40 MW)	15	1,561,513	300	389	
2035	Aeroderivative (40 MW)	15	1,642,725	313	404	
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,364	310	396	

Table 140. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - 250 MW CC and 500 MW CC available by 2021 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 141. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - 250 MW CC ($700/kW) included in 2023 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,005,072,016
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	18.04
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$7,015,839,143
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$172,501,719
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,644,939
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$79,970,382
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	1x1 NGCC (250 MW)	14.31	1,178,277	486	392	556
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Large GT (187 MW)					589
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					29.677
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
2024	PVNGS U2 Lease Purchase (10 MW)	15.34	1,136,398	484	371	$0
	Reciprocating Engines (41 MW)					**Outside Adjustment 2**
2025		14.16	1,157,269	486	380	$0
2026	Reciprocating Engines (41 MW)	15.02	1,173,616	495	385	**Outside Model Adjustment 3**
2027	Solar PV Large (50 MW)	14.59	1,134,159	472	363	$0
2028	Large GT (187 MW)	14.69	1,138,928	477	367	**Outside Model Adjustment 4**
2029	Solar PV Large (50 MW)	14.16	1,148,584	471	364	$0
2030	Solar PV Large (100 MW)	14.08	1,052,923	451	324	**Total Optimized NPV + Adjustments**
2031	Large GT (187 MW)	20.31	1,107,399	449	339	$7,005,072,016
2032	Four Corners Undepreciated Assets	17.89	1,539,789	303	394	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$7,015,839,143
	Wind (100 MW)					
2033	Wind (100 MW)	16	1,401,126	272	350	
2034		14	1,449,065	279	361	
2035	Aeroderivatives (80 MW)	16	1,516,211	289	373	
2036	Aeroderivative (40 MW)	15	1,630,293	308	394	

Table 142. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - 500 MW CC ($700/kW) included in 2023 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,098,359,094
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	26.39
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$7,109,171,609
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,445,007
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,740,010
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,141,568
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	2x1 NGCC (500 MW)	16.53	1,227,575	496	409	558
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					591
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
2024	PVNGS U2 Lease Purchase (10 MW)	15.56	1,184,561	495	388	27.042
2025		14.38	1,206,482	497	397	**Outside Adjustment 1**
2026	Solar PV Distribution (50 MW)	14.13	1,164,618	493	382	$0
2027	Solar PV Large (100 MW)	14.52	1,074,665	457	342	**Outside Adjustment 2**
2028	Large GT (187 MW)	14.62	1,080,651	463	346	$0
2029	Solar PV Large (50 MW)	14.09	1,090,920	457	344	**Outside Model Adjustment 3**
2030	Large GT (187 MW)	20.84	1,084,890	460	337	$0
2031		18.69	1,141,711	458	351	**Outside Model Adjustment 4**
2032	Four Corners Undepreciated Assets	16.31	1,572,689	310	403	$0
	Large GT (187 MW)					**Total Optimized NPV + Adjustments**
	Wind (100 MW)					$7,098,359,094
2033	Wind (100 MW)	14.56	1,433,118	279	359	**Average Risk NPV + Adjustments**
2034	Reciprocating Engines (41 MW)	14	1,478,618	285	369	$7,109,171,609
2035	Reciprocating Engines (41 MW)	14	1,541,306	294	380	
2036	Aeroderivative (40 MW)	14	1,592,063	301	385	
	Solar PV Large (50 MW)					

Table 143. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - H-Class NGCC's available by 2021 (405 MW and 202.5 MW) (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,943,522,391
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.59
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,954,222,380
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$184,500,589
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	56,395,623
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$84,431,912
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	1x1 NGCC-H Participation (202.5 MW)	20.26	1,242,501	493	409	574
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					618
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					27.461
2024	PVNGS U2 Lease Purchase (10 MW)	19.25	1,214,359	493	392	**Outside Adjustment 1**
2025		18.03	1,233,015	493	400	$0
2026		16.92	1,252,697	503	406	**Outside Adjustment 2**
2027		15.64	1,265,414	494	402	$0
2028	Large GT (187 MW)	15.73	1,270,965	499	406	**Outside Model Adjustment 3**
2029		14.39	1,330,364	505	421	$0
2030	Solar PV Large (50 MW)	14.30	1,223,610	483	377	**Outside Model Adjustment 4**
	Solar PV Distribution (50 MW)					$0
2031	Large GT (187 MW)	20.53	1,280,279	481	392	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	18.11	1,730,449	340	443	$6,943,522,391
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
	Wind (100 MW)					$6,954,222,380
2033	Wind (100 MW)	16	1,586,145	309	397	
2034		14	1,634,745	315	408	
2035	Reciprocating Engines (41 MW)	14	1,694,947	324	417	
2036	Reciprocating Engines (41 MW)	14	1,745,190	330	421	
	Solar PV Large (50 MW)					

Table 144. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - H-Class NGCC's available by 2021 (135 MW and 67.5 MW) (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,924,754,563
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.58
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,935,069,121
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$182,352,529
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	56,135,919
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$83,685,377
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	1x1 NGCC-H Participation (135 MW)	16.97	1,258,268	500	417	571
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					613
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					27.278
2024	PVNGS U2 Lease Purchase (10 MW)	15.99	1,229,310	500	399	**Outside Adjustment 1**
2025		14.81	1,247,009	500	407	$0
2026	Solar PV Distribution (50 MW)	14.55	1,208,118	496	392	**Outside Adjustment 2**
2027	Solar PV Large (50 MW)	14.13	1,171,745	474	371	$0
2028	Large GT (187 MW)	14.23	1,176,165	479	374	**Outside Model Adjustment 3**
2029	1x1 NGCC-H Participation (67.5 MW)	15.99	1,223,579	479	383	$0
2030		14.30	1,222,153	482	377	**Outside Model Adjustment 4**
2031	Large GT (187 MW)	20.53	1,278,874	481	391	$0
2032	Four Corners Undepreciated Assets	18.11	1,729,079	340	443	**Total Optimized NPV + Adjustments**
	Large GT (187 MW)					$6,924,754,563
	Wind (100 MW)					**Average Risk NPV + Adjustments**
2033	Wind (100 MW)	16	1,584,717	308	397	$6,935,069,121
2034		14	1,633,362	315	407	
2035	Reciprocating Engines (41 MW)	14	1,693,660	323	417	
2036	Reciprocating Engines (41 MW)	14	1,743,944	330	421	
	Solar PV Large (50 MW)					

Table 145. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - 500 MW NGCC (F-Class) at $237/kW included in 2023 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,781
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	18.04
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,594,854
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$172,501,719
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,644,939
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$79,970,382
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	1x1 NGCC (250 MW)	14.31	1,178,277	486	392	556
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Large GT (187 MW)					589
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					29.677
	Solar PV Distribution (50 MW)					**Outside Adjustment 1**
2024	PVNGS U2 Lease Purchase (10 MW)	15.34	1,136,398	484	371	$0
	Reciprocating Engines (41 MW)					**Outside Adjustment 2**
2025		14.16	1,157,269	486	380	$0
2026	Reciprocating Engines (41 MW)	15.02	1,173,616	495	385	**Outside Model Adjustment 3**
2027	Solar PV Large (50 MW)	14.59	1,134,159	472	363	$0
2028	Large GT (187 MW)	14.69	1,138,928	477	367	**Outside Model Adjustment 4**
2029	Solar PV Large (50 MW)	14.16	1,148,584	471	364	$0
2030	Solar PV Large (100 MW)	14.08	1,052,923	451	324	**Total Optimized NPV + Adjustments**
2031	Large GT (187 MW)	20.31	1,107,399	449	339	$6,956,827,781
2032	Four Corners Undepreciated Assets	17.89	1,539,789	303	394	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,594,854
	Wind (100 MW)					
2033	Wind (100 MW)	16	1,401,126	272	350	
2034		14	1,449,065	279	361	
2035		16	1,516,211	289	373	
2036	Aeroderivative (40 MW)	15	1,630,293	308	394	

Table 146. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Retires in 2031 - NGCC Sensitivity - 500 MW included at crossover cost (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,641
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	26.39
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,640,072
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,445,007
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,740,010
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,141,568
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	2x1 NGCC (500 MW)	16.53	1,227,575	496	409	558
	Data Center1 Solar6 (20 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					591
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
2024	PVNGS U2 Lease Purchase (10 MW)	15.56	1,184,561	495	388	27.042
2025		14.38	1,206,482	497	397	**Outside Adjustment 1**
2026	Solar PV Distribution (50 MW)	14.13	1,164,618	493	382	$0
2027	Solar PV Large (100 MW)	14.52	1,074,665	457	342	**Outside Adjustment 2**
2028	Large GT (187 MW)	14.62	1,080,651	463	346	$0
2029	Solar PV Large (50 MW)	14.09	1,090,920	457	344	**Outside Model Adjustment 3**
2030	Large GT (187 MW)	20.84	1,084,890	460	337	$0
2031		18.69	1,141,711	458	351	**Outside Model Adjustment 4**
2032	Four Corners Undepreciated Assets	16.31	1,572,689	310	403	$0
	Large GT (187 MW)					**Total Optimized NPV + Adjustments**
	Wind (100 MW)					$6,956,827,641
2033	Wind (100 MW)	14.56	1,433,118	279	359	**Average Risk NPV + Adjustments**
2034	Reciprocating Engines (41 MW)	14	1,478,618	285	369	$6,967,640,072
2035	Reciprocating Engines (41 MW)	14	1,541,306	294	380	
2036	Aeroderivative (40 MW)	14	1,592,063	301	385	
	Solar PV Large (50 MW)					

Table 147. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Exit in 2031 - 48 MW SMR Available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 148. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Exit in 2031 - 96 MW SMR Available (LOAD = MID, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO_2 Tons1	PNM CPP CO_2 lbs/MWh1	PNM NM CPP CO_2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO_2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO_2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO_2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO_2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 149. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Exit in 2031 - 114 MW SMR Available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 150. 2017 IRP: SJGS Retires in 2022 - PVNGS Included - FCPP Exit in 2031 - High Renewable Penetration Scenario (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$7,077,091,891
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	12.20
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$7,086,475,234
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$106,014,363
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	46,067,891
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	17.40	2,043,456	640	742	$58,768,654
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
	Wind (200 MW)					453
2023	Data Center1 Solar6 (20 MW)	14.22	629,658	354	198	**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					432
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					23.794
	Reciprocating Engines (41 MW)					**Outside Adjustment 1**
	Solar PV Large (50 MW)					$0
	Wind (200 MW)					**Outside Adjustment 2**
2024	PVNGS U2 Lease Purchase (10 MW)	15.25	610,878	355	187	$0
	Reciprocating Engines (41 MW)					**Outside Model Adjustment 3**
2025	Solar PV Large (50 MW)	15.74	560,000	336	169	$0
	Solar PV Distribution (50 MW)					**Outside Model Adjustment 4**
2026	Solar PV Large (100 MW)	16.30	526,526	329	155	$0
2027		15.04	533,138	320	154	**Total Optimized NPV + Adjustments**
2028	Large GT (187 MW)	15.13	542,288	327	158	$7,077,091,891
2029	Solar PV Large (100 MW)	15.39	537,227	316	152	**Average Risk NPV + Adjustments**
2030	Solar PV Large (100 MW)	15	507,750	304	138	$7,086,475,234
2031	Aeroderivative (40 MW)	15	544,527	303	147	
2032	Aeroderivative (40 MW)	14	986,124	188	239	
	Four Corners Undepreciated Assets					
	Large GT (187 MW)					
2033	Solar PV Large (150 MW)	15	954,939	179	222	
2034	Aeroderivative (40 MW)	14	989,278	184	229	
2035	Large GT (187 MW)	20	1,042,137	192	240	
2036		18	1,139,004	208	259	

Table 151. 2017 IRP: MCEP - Solar Sensitivity Base - 250 MW Solar available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 152. 2017 IRP: MCEP - Solar Sensitivity Base - Solar Cost Curve 2 (0% cost escalation) - 250 MW Solar PV available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,951,170,734
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,961,858,642
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,951,170,734
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,961,858,642
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 153. 2017 IRP: MCEP - Solar Sensitivity Base - Solar Cost Curve 3 (declining cost) - 1,250 MW Solar available (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,903,336,422
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	19.58
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,913,377,764
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$168,607,257
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,098,806
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$78,493,996
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	15.24	1,235,182	499	411	545
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					571
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					27.698
	Solar PV Transmission (50 MW) -2020 PRICING					**Outside Adjustment 1**
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,205,176	500	394	$0
2025	Solar PV Distribution (50 MW) -2024 PRICING	14.79	1,104,127	471	359	**Outside Adjustment 2**
	Solar PV Transmission (50 MW) -2024 PRICING					$0
2026	Solar PV Transmission (100 MW) -2024 PRICING	15.36	1,035,740	458	332	**Outside Model Adjustment 3**
2027		14.10	1,050,718	449	330	$0
2028	Large GT (187 MW)	14.21	1,052,169	454	333	**Outside Model Adjustment 4**
2029	Solar PV Transmission (100 MW) -2024 PRICING	14.48	1,034,602	438	318	$0
2030	Solar PV Transmission (100 MW) -2024 PRICING	14.39	983,520	424	290	**Total Optimized NPV + Adjustments**
2031	Aeroderivative (40 MW)	14.13	1,031,279	422	303	$6,903,336,422
2032	1x1 NGCC (250 MW)	14.34	1,510,194	294	382	**Average Risk NPV + Adjustments**
	Four Corners Undepreciated Assets					$6,913,377,764
2033	Solar PV Transmission (150 MW) -2024 PRICING	15	1,429,598	272	347	
2034	Aeroderivative (40 MW)	14	1,469,629	277	356	
2035	Aeroderivative (40 MW)	14	1,529,080	286	367	
2036	Rio Bravo CC Expansion (210 MW)	15	1,580,479	294	374	

Table 154. 2017 IRP: MCEP - Solar Sensitivity Base - Solar Cost Curve 2 (0% cost escalation) - Add additional 1x50 MW and 1x100 MW solar PV to database (400 MW total) (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,943,936,953
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.49
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,954,262,992
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$171,037,877
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,086,084
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$78,397,631
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	548
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					576
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					25.968
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Solar PV Large (50 MW)	14.53	1,077,585	470	348	$0
2027	Solar PV Large (50 MW)	14.10	1,050,718	449	330	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.21	1,052,169	454	333	$0
2029	Aeroderivative (40 MW)	14.71	1,109,308	460	347	**Outside Model Adjustment 4**
2030	Solar PV Large (50 MW)	14.05	922,213	418	278	$0
	Wind (100 MW)					**Total Optimized NPV + Adjustments**
2031	Large GT (187 MW)	20.28	973,425	417	292	$6,943,936,953
2032	Four Corners Undepreciated Assets	17.87	1,410,391	275	358	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,954,262,992
	Wind (100 MW)					
2033		16	1,452,166	281	361	
2034		14	1,498,442	287	371	
2035	Aeroderivative (40 MW)	15	1,475,712	278	358	
	Solar PV Large (100 MW)					
2036	Aeroderivative (40 MW)	14	1,598,974	300	382	

Table 155. 2017 IRP: MCEP - Solar Sensitivity Base - Solar Cost Curve 2 (0% cost escalation) - Add additional 2x50 MW and 5x100 MW solar PV to database (850 MW total) (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,951,277,422
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.55
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,961,163,202
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$163,955,331
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	53,521,899
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$77,106,555
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	540
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					561
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					25.895
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Aeroderivative (40 MW)	15.02	1,214,309	498	399	**Outside Adjustment 2**
2026	Solar PV Large (50 MW)	14.77	1,178,214	495	385	$0
2027	Solar PV Large (50 MW)	14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,400	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Aeroderivative (40 MW)	14.28	992,666	439	305	**Total Optimized NPV + Adjustments**
2031	Aeroderivative (40 MW)	14.01	1,049,948	438	320	$6,951,277,422
2032	Four Corners Undepreciated Assets	14.75	1,323,495	256	331	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,961,163,202
	Solar PV Large (200 MW)					
	Wind (100 MW)					
2033	Solar PV Large (100 MW)	14	1,291,383	245	312	
2034	Solar PV Large (50 MW)	15	1,248,432	233	293	
	Solar PV Large (100 MW)					
2035	Solar PV Large (100 MW)	14	1,267,634	233	291	
2036	Rio Bravo CC Expansion (210 MW)	15	1,273,009	233	289	

Table 156. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 157. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $40/MWh (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,939,937,016
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	16.63
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,950,723,018
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$157,899,830
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	53,129,043
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$75,958,529
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.09	1,189,627	489	395	538
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					562
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (41 MW)					25.797
	Solar PV Large (100 MW)					**Outside Adjustment 1**
2024	PVNGS U2 Lease Purchase (10 MW)	15.13	1,147,767	487	374	$0
	Reciprocating Engines (41 MW)					**Outside Adjustment 2**
2025	Wind (100 MW)	14.19	993,229	446	322	$0
2026	Solar PV Distribution (50 MW)	14.17	815,276	408	258	**Outside Model Adjustment 3**
	Wind (100 MW)					$0
2027	Aeroderivative (40 MW)	14.80	826,009	398	257	**Outside Model Adjustment 4**
2028	Large GT (187 MW)	14.90	833,165	404	260	$0
2029	Solar PV Large (50 MW)	14.37	844,139	400	259	**Total Optimized NPV + Adjustments**
2030	Large GT (187 MW)	21.11	846,566	404	256	$6,939,937,016
2031		18.96	898,757	403	271	**Average Risk NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16	1,518,550	298	388	$6,950,723,018
	Large GT (187 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,687	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 158. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $30/MWh (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,897,194,547
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	16.15
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,908,330,515
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$154,665,502
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	52,536,966
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$74,775,677
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.87	943,729	434	311	532
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					553
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					25.668
	Wind (200 MW)					**Outside Adjustment 1**
2024	PVNGS U2 Lease Purchase (10 MW)	14.76	863,906	421	276	$0
	Solar PV Distribution (50 MW)					**Outside Adjustment 2**
2025	Aeroderivative (40 MW)	15.50	880,953	420	284	$0
2026		14.41	899,367	431	290	**Outside Model Adjustment 3**
2027	Solar PV Large (100 MW)	14.80	826,009	398	257	$0
2028	Large GT (187 MW)	14.90	833,165	404	260	**Outside Model Adjustment 4**
2029	Solar PV Large (50 MW)	14.37	844,139	400	259	$0
2030	Large GT (187 MW)	21.11	846,566	404	256	**Total Optimized NPV + Adjustments**
2031		18.96	898,757	403	271	$6,897,194,547
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,908,330,515
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,687	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 159. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $20/MWh (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,850,646,906
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	12.70
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,862,037,431
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$155,101,766
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	52,145,674
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	17.40	2,043,456	640	742	$73,698,293
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
	Wind (200 MW)					528
2023	Data Center1 Solar6 (20 MW)	14.87	943,729	434	311	**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					546
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					25.495
	Reciprocating Engines (82 MW)					**Outside Adjustment 1**
2024	PVNGS U2 Lease Purchase (10 MW)	14.76	863,906	421	276	$0
	Solar PV Distribution (50 MW)					**Outside Adjustment 2**
2025	Aeroderivative (40 MW)	15.50	880,953	420	284	$0
2026		14.41	899,367	431	290	**Outside Model Adjustment 3**
2027	Solar PV Large (100 MW)	14.80	826,009	398	257	$0
2028	Large GT (187 MW)	14.90	833,165	404	260	**Outside Model Adjustment 4**
2029	Solar PV Large (50 MW)	14.37	844,139	400	259	$0
2030	Large GT (187 MW)	21.11	846,566	404	256	**Total Optimized NPV + Adjustments**
2031		18.96	898,757	403	271	$6,850,646,906
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,862,037,431
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,687	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 160. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $46.85/MWh (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (100 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 161. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $46.85/MWh, 50 MW sizing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,961,696,188
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.29
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,972,374,259
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$182,161,949
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	56,113,571
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$83,386,979
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	571
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					612
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.526
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Aeroderivative (40 MW)	15.02	1,214,309	498	399	**Outside Adjustment 2**
2026	Wind (50 MW)	14.06	1,146,286	489	375	$0
2027	Solar PV Large (100 MW)	14.45	1,057,163	454	335	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.55	1,058,793	458	338	$0
2029	Solar PV Large (50 MW)	14.03	1,071,707	453	336	**Outside Model Adjustment 4**
2030	Large GT (187 MW)	20.77	1,071,739	457	331	$0
2031		18.63	1,131,420	456	347	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16.14	1,715,647	338	440	$6,961,696,188
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
	Wind (50 MW)					$6,972,374,259
2033		14	1,764,462	344	443	
2034	Aeroderivative (40 MW)	14	1,814,713	351	454	
2035	Aeroderivative (40 MW)	14	1,831,270	350	451	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,826,160	346	442	

Table 162. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $46.85/MWh, 150 MW sizing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,952,770,219
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	16.99
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,963,446,330
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$163,794,714
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	53,838,737
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$77,726,123
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	547
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					574
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.041
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.25	915,847	417	284	**Outside Model Adjustment 4**
	Wind (150 MW)					$0
2030	Large GT (187 MW)	21.00	917,385	421	280	**Total Optimized NPV + Adjustments**
2031		18.85	972,192	420	295	$6,952,770,219
2032	Four Corners Undepreciated Assets	16.57	1,333,184	261	339	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,963,446,330
	Wind (150 MW)					
2033		15	1,373,835	267	343	
2034	Aeroderivative (40 MW)	14	1,421,698	273	353	
2035	Aeroderivative (40 MW)	14	1,496,890	285	368	
2036	Rio Bravo CC Expansion (210 MW)	15	1,518,672	287	367	

Table 163. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $46.85/MWh, 200 MW sizing (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,951,168,016
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.24
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,961,923,797
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$168,796,372
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	53,782,927
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$77,984,304
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	547
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					573
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.056
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Aeroderivative (40 MW)	14.94	1,207,325	485	383	**Outside Model Adjustment 4**
2030	Solar PV Large (50 MW)	14.05	1,155,224	476	359	$0
2031	Large GT (187 MW)	20.28	1,216,834	475	375	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	18.52	1,161,172	226	293	$6,951,168,016
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
	Wind (400 MW)					$6,961,923,797
2033		17	1,198,173	231	297	
2034		15	1,244,486	238	307	
2035	Aeroderivative (40 MW)	14	1,314,090	249	321	
2036	Rio Bravo CC Expansion (210 MW)	15	1,345,687	254	324	

Table 164. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $46.85/MWh, 100 MW sizing, 45% capacity factor (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,956,827,594
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,967,515,573
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$174,726,831
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,905,569
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,418,242	736	922	$80,446,356
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,298,049	514	433	558
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.270
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,199,177	499	392	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,104,127	471	359	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,125,148	482	366	$0
2027		14.34	1,142,917	473	364	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,142,401	478	367	$0
2029	Solar PV Large (50 MW)	14.14	991,724	435	309	**Outside Model Adjustment 4**
	Wind (200 MW)					$0
2030	Large GT (187 MW)	20.89	992,444	439	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,049,826	438	320	$6,956,827,594
2032	Four Corners Undepreciated Assets	16.35	1,518,550	298	388	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,967,515,573
	Wind (200 MW)					
2033		14	1,563,348	304	392	
2034	Aeroderivative (40 MW)	14	1,612,695	311	402	
2035	Aeroderivative (40 MW)	15	1,630,686	311	401	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,497	310	396	

Table 165. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $46.85/MWh, 100 MW sizing, 25% capacity factor (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,950,985,281
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,423,703	995	1,490	22.83
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.27	3,132,575	928	1,328	$6,961,036,444
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.06	3,015,658	890	1,234	$192,339,731
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.06	3,065,101	877	1,209	57,736,083
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.73	2,583,311	775	997	$86,489,857
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.19	1,452,495	547	486	588
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					637
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.967
2024	PVNGS U2 Lease Purchase (10 MW)	14.09	1,349,830	533	443	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.59	1,244,428	503	407	**Outside Adjustment 2**
2026	Solar PV Large (50 MW)	14.34	1,213,119	501	395	$0
2027	Solar PV Large (50 MW)	14.05	1,089,945	458	343	**Outside Model Adjustment 3**
	Wind (100 MW)					$0
2028	Large GT (187 MW)	14.15	1,090,487	463	346	**Outside Model Adjustment 4**
2029	Large GT (187 MW)	21.36	1,149,262	469	361	$0
2030		19.60	1,149,954	473	356	**Total Optimized NPV + Adjustments**
2031	Wind (100 MW)	17.59	1,116,760	451	341	$6,950,985,281
2032	Four Corners Undepreciated Assets	15.01	1,791,510	353	459	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,961,036,444
2033	Aeroderivative (40 MW)	15	1,841,391	359	462	
2034	Aeroderivative (40 MW)	15	1,891,166	365	473	
2035	Aeroderivative (40 MW)	14	1,974,597	378	487	
2036	Rio Bravo CC Expansion (210 MW)	15	1,957,706	371	474	

Table 166. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $46.85/MWh, 100 MW sizing, 55% capacity factor (LOAD = MID, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,959,185,016
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,416,998	993	1,487	15.35
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.35	3,048,589	907	1,286	$6,970,085,823
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.23	2,863,378	851	1,158	$167,872,603
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.29	2,841,939	822	1,102	54,072,171
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	17.01	2,339,375	717	886	$78,894,694
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.48	1,222,252	497	407	550
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					578
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.051
2024	PVNGS U2 Lease Purchase (10 MW)	14.38	1,126,014	482	367	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Aeroderivative (40 MW)	15.12	1,141,800	482	374	**Outside Adjustment 2**
2026		14.03	1,163,310	492	381	$0
2027	Solar PV Large (100 MW)	14.43	1,073,331	457	341	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.53	1,074,542	462	343	$0
2029	Solar PV Large (50 MW)	14.00	1,087,542	457	342	**Outside Model Adjustment 4**
2030	Large GT (187 MW)	20.75	1,087,431	461	337	$0
2031		18.61	1,147,519	460	353	**Total Optimized NPV + Adjustments**
2032	Four Corners Undepreciated Assets	16.54	1,359,686	266	346	$6,959,185,016
	Large GT (187 MW)					**Average Risk NPV + Adjustments**
	Wind (200 MW)					$6,970,085,823
2033		15	1,400,939	272	350	
2034	Aeroderivative (40 MW)	14	1,449,017	279	360	
2035	Aeroderivative (40 MW)	14	1,524,883	291	375	
2036	Rio Bravo CC Expansion (210 MW)	15	1,544,947	292	373	

Table 167. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 - Wind at $20/MWh, 200 MW sizing, 55% capacity factor (LOAD = MID, GAS = MID, CO_2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,746,933,906
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,416,998	993	1,487	11.08
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.35	3,048,589	907	1,286	$6,757,709,844
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.23	2,863,378	851	1,158	$109,558,295
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.29	2,841,939	822	1,102	46,201,547
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	17.61	1,920,435	605	679	$59,690,894
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
	Wind (200 MW)					459
2023	Data Center1 Solar6 (20 MW)	15.68	523,224	326	161	**20-Year PNM NM CO2 (lbs/MWh)**
	2 x Large GT (374 MW)					445
	Palo Verde Undepreciated Assets					**20-Year Freshwater (Bn of Gal)**
	PVNGS U1 Lease Purchase (104 MW)					23.877
	Reciprocating Engines (82 MW)					**Outside Adjustment 1**
	Wind (200 MW)					$0
2024	PVNGS U2 Lease Purchase (10 MW)	14.72	514,584	328	154	**Outside Adjustment 2**
2025	Aeroderivative (40 MW)	15.46	526,278	327	159	$0
2026		14.37	538,647	337	163	**Outside Model Adjustment 3**
2027	Aeroderivative (40 MW)	14.99	546,580	328	162	$0
2028	Large GT (187 MW)	15.08	560,052	335	167	**Outside Model Adjustment 4**
2029	Solar PV Distribution (50 MW)	14.55	552,820	328	163	$0
2030	Large GT (187 MW)	21.29	559,675	333	162	**Total Optimized NPV + Adjustments**
2031		19.14	600,282	331	174	$6,746,933,906
2032	Four Corners Undepreciated Assets	16.53	1,096,687	214	278	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,757,709,844
2033		15	1,132,533	219	282	
2034	Solar PV Large (100 MW)	14	1,080,692	206	265	
2035	Aeroderivative (40 MW)	15	1,097,606	207	265	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,137,741	213	271	

Table 168. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = MID, GAS = HIGH, CO2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,360	1,302	1,682	$7,380,834,000
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,415,016	995	1,489	16.41
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,069,838	915	1,301	$7,400,660,738
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,910,535	865	1,183	$223,218,223
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,910,054	841	1,137	51,753,386
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,409,932	738	922	$137,452,108
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.34	996,936	453	330	522
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					533
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (41 MW)					25.674
	Solar PV Large (100 MW)					**Outside Adjustment 1**
	Wind (100 MW)					$0
2024	PVNGS U2 Lease Purchase (10 MW)	14.47	777,607	404	246	**Outside Adjustment 2**
	Solar PV Distribution (50 MW)					$0
	Wind (100 MW)					**Outside Model Adjustment 3**
2025	Solar PV Large (50 MW)	14.14	757,173	392	238	$0
2026	Reciprocating Engines (41 MW)	15.00	766,561	401	241	**Outside Model Adjustment 4**
2027	Solar PV Large (50 MW)	14.57	747,191	382	228	$0
2028	Large GT (187 MW)	14.67	755,226	389	232	**Total Optimized NPV + Adjustments**
2029	Large GT (187 MW)	21.87	799,785	394	244	$7,380,834,000
2030		20.10	802,022	398	241	**Average Risk NPV + Adjustments**
2031		18	855,043	396	256	$7,400,660,738
2032	Four Corners Undepreciated Assets	15	1,472,324	288	375	
	Large GT (187 MW)					
2033	Rio Bravo CC Expansion (210 MW)	17	1,408,150	274	352	
2034		15	1,455,142	280	362	
2035	Aeroderivative (40 MW)	14	1,524,068	291	375	
2036	Aeroderivatives (80 MW)	15	1,640,370	310	396	

Table 169. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = MID, GAS = MID, CO2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.30	4,821,424	1,302	1,682	$6,867,003,828
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	17.61	3,419,248	994	1,488	17.11
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	18.32	3,076,591	914	1,300	$6,876,007,262
	NMWEC Repower + 50 MW Solar PV for RPS					**Risk Portfolio Tail (NPV)**
2020	Data Center1 Solar3 (30 MW)	18.17	2,913,392	864	1,183	$175,897,684
	Data Center1 Wind2 (50 MW)					**20-Year CO2 (Tons)**
2021	Data Center1 Solar4 (30 MW)	17.21	2,913,939	840	1,137	54,975,461
	Data Center1 Wind3 (50 MW)					**20-Year CO2 Cost (NPV)**
2022	Data Center1 Solar5 (40 MW)	16.91	2,417,507	736	922	$0
	Data Center1 Wind4 (30 MW)					**20-Year PNM CO2 (lbs/MWh)**
2023	Data Center1 Solar6 (20 MW)	14.39	1,293,158	515	433	559
	2 x Large GT (374 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Palo Verde Undepreciated Assets					592
	PVNGS U1 Lease Purchase (104 MW)					**20-Year Freshwater (Bn of Gal)**
	Reciprocating Engines (82 MW)					26.274
2024	PVNGS U2 Lease Purchase (10 MW)	14.28	1,193,589	500	391	**Outside Adjustment 1**
	Solar PV Distribution (50 MW)					$0
2025	Solar PV Large (100 MW)	14.79	1,101,284	472	358	**Outside Adjustment 2**
2026	Aeroderivative (40 MW)	15.59	1,124,386	482	366	$0
2027		14.34	1,138,180	474	363	**Outside Model Adjustment 3**
2028	Large GT (187 MW)	14.44	1,138,355	479	366	$0
2029	Solar PV Large (50 MW)	14.14	989,147	436	309	**Outside Model Adjustment 4**
	Wind (100 MW)					$0
2030	Large GT (187 MW)	20.89	989,734	440	305	**Total Optimized NPV + Adjustments**
2031		18.74	1,046,465	439	320	$6,867,003,828
2032	Four Corners Undepreciated Assets	16.35	1,524,301	299	390	**Average Risk NPV + Adjustments**
	Large GT (187 MW)					$6,876,007,262
	Wind (100 MW)					
2033		14	1,569,557	306	393	
2034	Aeroderivative (40 MW)	14	1,618,925	312	404	
2035	Aeroderivative (40 MW)	15	1,639,892	313	403	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	15	1,640,627	310	396	

Table 170. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = HIGH, GAS = LOW, CO2 = LOW)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,159,761,094
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,471,672	993	1,476	16.53
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,081,239	894	1,252	$7,151,767,141
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$142,561,385
2020	Data Center1 Solar3 (30 MW)	14.25	3,006,100	846	1,131	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					71,146,700
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$19,958,253
2021	Data Center1 Solar4 (30 MW)	19.77	3,224,166	845	1,116	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					629
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,908,200	756	936	695
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Aeroderivative (40 MW)	15.14	1,755,411	518	475	38.296
	1x1 NGCC (250 MW)					**Outside Adjustment 1**
	Data Center1 Solar6 (20 MW)					$0
	Large GT (187 MW)					**Outside Adjustment 2**
	Palo Verde Undepreciated Assets					$0
	PVNGS U1 Lease Purchase (104 MW)					**Outside Model Adjustment 3**
	Reciprocating Engines (41 MW)					$0
2024	Large GT (187 MW)	20.11	1,856,276	530	477	**Outside Model Adjustment 4**
	PVNGS U2 Lease Purchase (10 MW)					$0
2025		17.91	1,965,282	534	496	**Total Optimized NPV + Adjustments**
2026		16.34	2,021,773	546	506	$7,159,761,094
2027		14.67	2,056,586	544	504	**Average Risk NPV + Adjustments**
2028	Large GT (187 MW)	14	2,102,427	549	512	$7,151,767,141
2029	Aeroderivative (40 MW)	14	2,195,185	557	526	
2030	Large GT (187 MW)	19	2,232,415	563	525	
2031		17	2,335,594	564	540	
2032	Four Corners Undepreciated Assets	14	3,057,037	495	612	
	Large GT (187 MW)					
2033	Small GT (85 MW)	15	3,125,009	499	611	
2034	Aeroderivative (40 MW)	14	3,215,229	506	622	
2035	Solar PV Large (50 MW)	14	3,126,535	486	594	
	Solar PV Large (100 MW)					
2036	Rio Bravo CC Expansion (210 MW)	14	3,147,213	482	585	

Table 171. 2017 IRP: SJGS Retires in 2022 - With Data Center2 Resources Included (LOAD = HIGH, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,802,586,625
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,467,606	1,003	1,504	24.74
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.30	3,088,155	957	1,422	$7,798,882,810
	Data Center2 Solar1 (150 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$176,857,145
2020	Data Center1 Solar3 (30 MW)	16.07	2,809,995	924	1,376	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					55,336,872
	Data Center2 Solar2 (150 MW)					**20-Year CO2 Cost (NPV)**
2021	Data Center1 Solar4 (30 MW)	18.16	2,890,791	931	1,397	$82,107,568
	Data Center1 Wind3 (50 MW)					**20-Year PNM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	15.85	2,280,087	814	1,155	631
	Data Center1 Wind4 (30 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
	Data Center2 Wind1 (200 MW)					721
	Data Center2 Wind2 (100 MW)					**20-Year Freshwater (Bn of Gal)**
2023	Aeroderivative (40 MW)	14.09	1,028,876	538	459	26.010
	Data Center1 Solar6 (20 MW)					**Outside Adjustment 1**
	2 x Large GT (374 MW)					$0
	Data Center2 Wind3 (100 MW)					**Outside Adjustment 2**
	Palo Verde Undepreciated Assets					$0
	PVNGS U1 Lease Purchase (104 MW)					**Outside Model Adjustment 3**
	Reciprocating Engines (82 MW)					$0
	Solar PV Distribution (50 MW)					**Outside Model Adjustment 4**
2024	Large GT (187 MW)	19.29	983,629	536	431	$0
	PVNGS U2 Lease Purchase (10 MW)					**Total Optimized NPV + Adjustments**
2025		17.11	1,048,996	541	453	$7,802,586,625
2026		15.55	1,093,367	557	468	**Average Risk NPV + Adjustments**
2027	Solar PV Large (50 MW)	15	1,100,278	536	448	$7,798,882,810
2028	Large GT (187 MW)	14	1,135,934	546	460	
2029	Large GT (187 MW)	20	1,204,277	554	480	
2030		18	1,241,164	562	479	
2031		15	1,325,905	563	503	
2032	Four Corners Undepreciated Assets	14	1,734,346	385	521	
	Large GT (187 MW)					
	Solar PV Large (100 MW)					
	Wind (100 MW)					
2033	Small GT (85 MW)	15	1,616,872	351	466	
	Wind (100 MW)					
2034	Aeroderivative (40 MW)	15	1,697,594	362	483	
2035	Aeroderivative (40 MW)	14	1,756,808	367	486	
	Solar PV Large (50 MW)					
2036	Rio Bravo CC Expansion (210 MW)	14	1,777,781	366	479	

Table 172. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = HIGH, GAS = MID, CO2 = MID)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,937,091,844
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,467,606	993	1,477	15.67
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,070,905	896	1,253	$7,931,836,084
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$259,063,204
2020	Data Center1 Solar3 (30 MW)	14.25	2,990,417	849	1,133	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					65,960,408
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$106,333,414
2021	Data Center1 Solar4 (30 MW)	19.77	3,206,960	848	1,117	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					583
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,901,000	766	944	619
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	1x1 NGCC (250 MW)	14.18	1,640,309	516	451	35.419
	Data Center1 Solar6 (20 MW)					**Outside Adjustment 1**
	Large GT (187 MW)					$0
	Palo Verde Undepreciated Assets					**Outside Adjustment 2**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Reciprocating Engines (41 MW)					**Outside Model Adjustment 3**
	Solar PV Large (50 MW)					$0
2024	Large GT (187 MW)	19.17	1,739,583	528	454	**Outside Model Adjustment 4**
	PVNGS U2 Lease Purchase (10 MW)					$0
2025		16.98	1,834,820	535	471	**Total Optimized NPV + Adjustments**
2026	Wind (100 MW)	15.63	1,704,466	513	434	$7,937,091,844
2027	Wind (100 MW)	14.17	1,573,605	475	389	**Average Risk NPV + Adjustments**
2028	Large GT (187 MW)	15	1,500,401	461	368	$7,931,836,084
	Solar PV Large (100 MW)					
2029	Aeroderivative (40 MW)	15	1,586,065	469	383	
2030	Aeroderivative (40 MW)	14	1,616,594	475	383	
2031	Large GT (187 MW)	19	1,712,407	477	400	
2032	Four Corners Undepreciated Assets	17	2,440,301	395	489	
	Large GT (187 MW)					
2033		14	2,525,721	404	494	
2034	Small GT (85 MW)	15	2,600,829	410	503	
2035	Aeroderivative (40 MW)	14	2,718,118	422	517	
2036	Rio Bravo CC Expansion (210 MW)	14	2,761,279	423	513	

Table 173. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = HIGH, GAS = HIGH, CO2 = HIGH)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,207	1,304	1,682	$8,599,196,250
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,463,429	994	1,478	15.48
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,065,382	897	1,254	$8,593,245,740
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$378,795,648
2020	Data Center1 Solar3 (30 MW)	14.25	2,986,882	850	1,133	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					64,578,445
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$194,655,331
2021	Data Center1 Solar4 (30 MW)	19.77	3,201,386	850	1,118	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					570
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,893,348	768	944	598
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	1x1 NGCC (250 MW)	14.13	1,341,156	465	368	34.605
	Data Center1 Solar6 (20 MW)					**Outside Adjustment 1**
	Large GT (187 MW)					$0
	Palo Verde Undepreciated Assets					**Outside Adjustment 2**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Solar PV Large (50 MW)					**Outside Model Adjustment 3**
	Solar PV Large (100 MW)					$0
	Wind (100 MW)					**Outside Model Adjustment 4**
2024	Large GT (187 MW)	19.33	1,270,654	445	329	$0
	PVNGS U2 Lease Purchase (10 MW)					**Total Optimized NPV + Adjustments**
	Wind (100 MW)					$8,599,196,250
2025		17.15	1,359,500	452	347	**Average Risk NPV + Adjustments**
2026		16	1,409,649	464	357	$8,593,245,740
2027	Reciprocating Engines (41 MW)	16	1,442,731	457	357	
2028	Large GT (187 MW)	15	1,484,846	465	366	
2029	Aeroderivative (40 MW)	15	1,571,021	473	382	
2030	Aeroderivative (40 MW)	14	1,601,421	479	382	
2031	Large GT (187 MW)	19	1,702,949	480	399	
2032	Four Corners Undepreciated Assets	17	2,452,564	397	491	
	Large GT (187 MW)					
2033		14	2,539,706	406	497	
2034	Small GT (85 MW)	15	2,609,202	411	505	
2035	Aeroderivative (40 MW)	14	2,730,079	424	519	
2036	Rio Bravo CC Expansion (210 MW)	14	2,761,081	423	513	

Table 174. 2017 IRP: SJGS Retires in 2022 - PVNGS Lease Purchases included, FCPP Exit in 2031 (LOAD = HIGH, GAS = MID, CO2 = $0)

Year	Resource	Reserve Margin	PNM NM CPP CO2 Tons1	PNM CPP CO2 lbs/MWh1	PNM NM CPP CO2 lbs/MWh1	Optimized Portfolio (NPV)
2017	FCPP Maint./Outage Capital	26.02	4,860,275	1,304	1,682	$7,815,158,750
	San Juan Undepreciated Assets					**Portfolio LOLH (Hours)**
2018	Data Center1 Solar1 (30 MW)	14.69	3,467,606	993	1,477	16.06
	Data Center1 Wind1 (50 MW)					**Risk Porfolio Average (NPV)**
2019	Data Center1 Solar2 (40 MW)	14.41	3,070,905	896	1,253	$7,808,556,180
	Solar PV Distribution (50 MW)					**Risk Portfolio Tail (NPV)**
	NMWEC Repower + 50 MW Solar PV for RPS					$272,696,809
2020	Data Center1 Solar3 (30 MW)	14.25	2,990,417	849	1,133	**20-Year CO2 (Tons)**
	Data Center1 Wind2 (50 MW)					67,613,605
	Reciprocating Engines (41 MW)					**20-Year CO2 Cost (NPV)**
	Solar PV Large (50 MW)					$0
2021	Data Center1 Solar4 (30 MW)	19.77	3,206,960	848	1,117	**20-Year PNM CO2 (lbs/MWh)**
	Data Center1 Wind3 (50 MW)					598
	Large GT (187 MW)					**20-Year PNM NM CO2 (lbs/MWh)**
2022	Data Center1 Solar5 (40 MW)	16.96	2,900,217	766	944	639
	Data Center1 Wind4 (30 MW)					**20-Year Freshwater (Bn of Gal)**
2023	1x1 NGCC (250 MW)	14.18	1,633,394	518	450	36.241
	Data Center1 Solar6 (20 MW)					**Outside Adjustment 1**
	Large GT (187 MW)					$0
	Palo Verde Undepreciated Assets					**Outside Adjustment 2**
	PVNGS U1 Lease Purchase (104 MW)					$0
	Reciprocating Engines (41 MW)					**Outside Model Adjustment 3**
	Solar PV Large (50 MW)					$0
2024	Large GT (187 MW)	19.17	1,731,462	530	453	**Outside Model Adjustment 4**
	PVNGS U2 Lease Purchase (10 MW)					$0
2025		16.98	1,831,213	536	471	**Total Optimized NPV + Adjustments**
2026		15.43	1,888,190	547	481	$7,815,158,750
2027	Solar PV Large (100 MW)	15.18	1,809,346	519	449	**Average Risk NPV + Adjustments**
2028	Large GT (187 MW)	15	1,847,399	527	457	$7,808,556,180
2029	Aeroderivative (40 MW)	15	1,940,788	534	472	
2030	Aeroderivative (40 MW)	14	1,789,809	508	426	
	Wind (100 MW)					
2031	Large GT (187 MW)	19	1,887,895	510	443	
2032	Four Corners Undepreciated Assets	17	2,446,770	396	490	
	Large GT (187 MW)					
	Wind (100 MW)					
2033		14	2,532,726	405	495	
2034	Small GT (85 MW)	15	2,606,882	411	504	
2035	Aeroderivative (40 MW)	14	2,727,294	424	518	
2036	Rio Bravo CC Expansion (210 MW)	14	2,761,392	423	513	

APPENDIX P. RELIABILITY ANALYSIS STUDY

2017

PNM 2017 Reliability and System Flexibility Study

Astrapé Consulting

CONTENTS

EXECUTIVE SUMMARY

This study was performed by Astrapé Consulting at the request of PNM's Resource Planning Department. As wind and solar resources are added to the system, the intermittent nature of these resources causes an increase in system commitment and dispatch uncertainty, impacting both reliability and cost. The purpose of this study is to understand the reliability of the portfolio currently projected by PNM as well as potential renewable portfolios with significantly higher renewable penetration.

From an operational standpoint, incremental renewable resources increase net load[6] uncertainty on a day ahead, multi-hour ahead, and intra-hour basis. This additional uncertainty requires planners to analyze the flexibility of their generation portfolio to ensure that the system can match generation and load on a real-time basis and minimize firm load shed events and renewable curtailment (over-generation periods). As wind or solar resources unexpectedly ramp up or down in output, the dispatch of the rest of the generation fleet must be changed rapidly to accommodate the change in net load. If the conventional fleet is not flexible enough to keep load and generation balanced, either reserve shortages or generation curtailment will occur. Typically, load shed events related to system ramping constraints are not included in traditional Loss of Load Expectation (LOLE) studies used for resource adequacy planning. These increased reliability events and renewable generation curtailment events are often mitigated by increasing system ancillary services such as load following reserve targets. By increasing the amount of online generation synched to the grid, the system can better meet short-term flexibility requirements, albeit at a cost.

Another way to mitigate reliability events caused by system inflexibility is adding flexible resources to the system. These types of resources start and ramp up quickly and include highly flexible turn-

[6] Net load is load, net of any renewables or must run resources, and represents the amount of load that the dispatchable generation fleet will ultimately have to serve.

down ratios to better manage the system. Examples of these types of resources include quick start peaking units and battery storage resources.

To understand the impact of adding new renewable resources, Astrapé has used its Strategic Energy and Risk Valuation Model (SERVM) to model the system and complete the following goals:

(1) Calculate the required installed reserve margin to meet acceptable reliability for the PNM Balancing Area (BA).

(2) Calculate reliability metrics and total system costs for multiple portfolios and determine the load following requirements necessary to maintain reliability.

(3) Calculate reliability metrics and total system costs for a number of different renewable penetrations, and determine the load following requirements necessary to maintain reliability.

(4) Calculate the benefit of adding flexible resources to the current portfolio and higher renewable penetration scenarios.

Typical planning studies utilize load shapes and renewable profiles from a single weather year and simulate only average unit performance characteristics. Since flexibility and reliability issues are high-impact, low-probability events, a large number of scenarios of load, renewable output, and conventional generator performance should be considered to adequately capture their expected frequency and impact. Further, it is also impossible to understand system flexibility issues in models that do not have chronological dispatch of units to take into account unit start up times, ramp rates, minimum up times, and minimum down times. The impact of renewable integration is dependent on annual weather patterns, economic growth characteristics, and unit performance metrics, among other variables. In order to capture the full impact intermittent resources have on the system, this study takes a stochastic approach in modeling the uncertainty of weather on loads and renewable profiles, economic growth uncertainty, unit availability, and transmission availability with neighboring utilities. Utilizing the chronological production cost and reliability software SERVM[7], over 2,500 yearly simulations were performed at 5-minute time steps for each portfolio analyzed to perform the four goals outlined above. The SERVM simulation engine considers all unit constraints, and incorporates the load, and renewable output variability and uncertainty that system operators manage on a real-time basis to assess system flexibility and renewable integration costs. SERVM reports many reliability metrics including $LOLE_{CAP}$, $LOLE_{FLEX}$, renewable curtailment, and EUE as well as PNM Balancing Area Costs. Below are the definitions of these metrics.

(1) $LOLE_{CAP}$: number of loss of load events due to capacity shortages, calculated in events per year. Traditional LOLE calculations only calculate $LOLE_{CAP}$.

(2) $LOLE_{FLEX}$: number of loss of load events due to system flexibility problems, calculated in events per year. In other words, there was enough capacity installed but not enough flexibility to meet the net load ramps, or startup times prevented a unit coming online fast enough to meet the unanticipated ramps.

(3) Renewable curtailment: Renewable curtailment occurs during over-generation periods when the system cannot ramp down fast enough to meet net load.

(4) PNM Balancing Area Costs: Production costs + Net Purchase costs + Expected Unserved Energy Costs. Production costs include all fuel burn , variable O&M, startup costs, and CO_2 costs. Costs for renewable generation are based on Power Purchase Agreement (PPA) pricing.

Installed Reserve Margin Requirement

A prerequisite of identifying the proper installed reserve margin requirement is identifying an appropriate level of reliability for the PNM system. The industry-standard reliability threshold is 1 firm load shed event in ten years. This is known as the '0.1 LOLE' or '1-in-10 LOLE' standard. For

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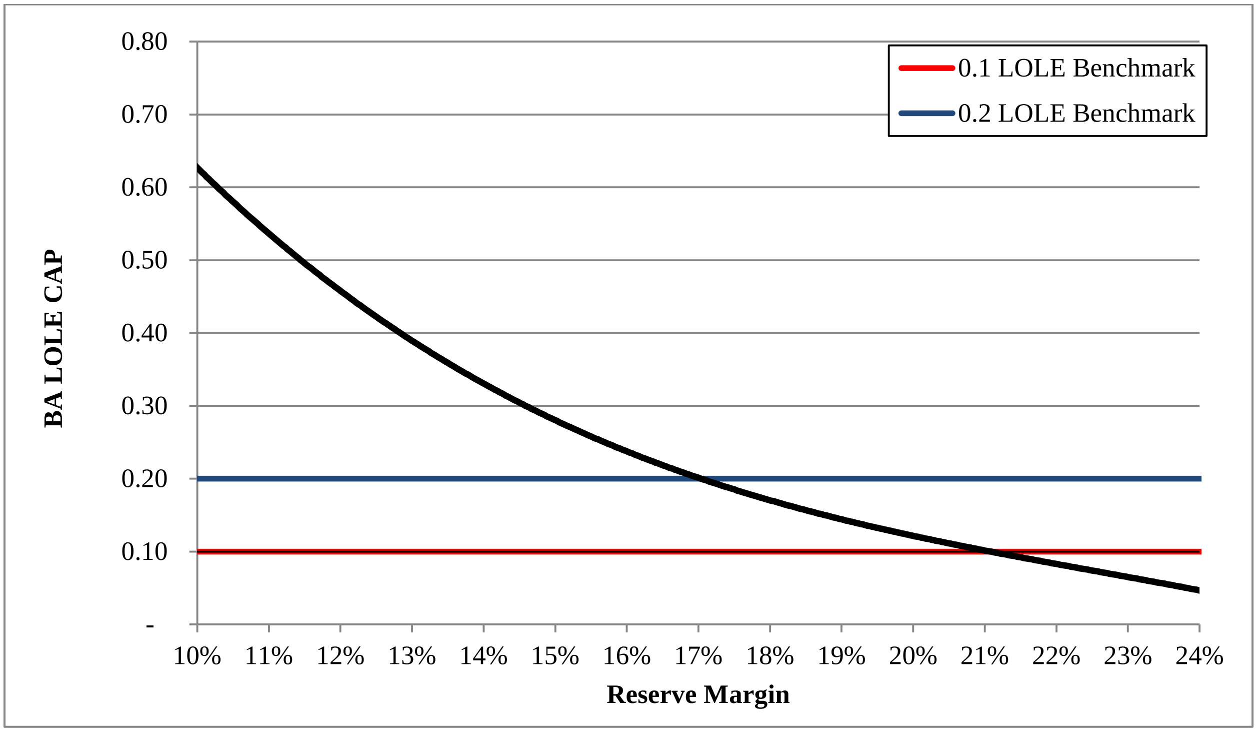
[7] As discussed in more detail in the body of the report, SERVM is used by utilities, regulators, and grid operators across the country to analyze resource adequacy and renewable integration.

small systems with limited interconnections, this level of reliability is difficult to achieve. The simultaneous forced outage of two larger units during peak conditions puts significant risk on a small system compared to a larger system with more than 50 generators. Based on the size of PNM, Astrapé recommends that PNM target a 0.2 LOLE (two events in ten years) standard at a minimum. The reserve margin study results show that a minimum reserve margin target of 17% is needed to maintain 0.2 $LOLE_{CAP}$[8]. Figure ES1 shows those results. At the current 13% minimum reserve margin, four events in 10 years are expected.

Figure ES1. Reserve Margin Study Results



[8] Typical industry standards do not distinguish $LOLE_{CAP}$ from $LOLE_{FLEX,}$ but rather assume that any system being modeled has adequate flexibility to avoid all $LOLE_{FLEX.}$ Since this analysis covers both flexibility and capacity needs, this report will maintain the distinction and refer to $LOLE_{CAP}$ for any measurement used to assess capacity needs.

The sensitivity analysis showed substantial risk in the market assistance assumptions. If market assistance was capped at 300 MW or 150 MW in high load hours[9], then the reserve margins required to meet 0.2 LOLE are 22.5% and 27.5% respectively. Given recent changes in Arizona and other WECC markets as well as a review of historical hourly purchases in the last several years, Astrapé recommends maintaining a minimum of17% reserve margin for the balancing area. Even at a 17% reserve margin, the balancing area still has risk if import capacity deteriorates.

Reliability and Economic Metrics

Table ES1 shows the flexibility reliability metrics and system production costs of the current portfolio plan for 2021 and 2024 which has San Juan 1 and 4 retiring in 2022. As discussed in the report, the other plan analyzed has San Juan 1 and 4 continuing in 2024 The renewable penetration in the balancing area is 17% in 2021 and 19% in 2024. The results show the system is reliable from a capacity and system flexibility standpoint for 2021 and 2024 assuming the Base Case external market assumptions. The load following target needed to maintain a reasonable $LOLE_{FLEX}$ value is 7% of load in addition to the 4% required for regulation reserves. PNM balance area costs increase as the load following target increases. Renewable curtailment which represents over-generation also increases slightly with higher load following targets. While renewable curtailment is only 1%, renewable curtailment events add additional risk to operators on a real time basis and also increase costs since the energy is assumed to be paid for at the PPA price regardless of whether or not it is used to serve load.

[9] As discussed in more detail in the report, the 300 MW and 150 MW sensitivities were developed based on reviewing previous years actual historical purchases during peak hours

Table ES1. Flexibility Metrics

	BA Renewable Penetration/ PNM Renewable Gen[10]	LF Target	Renewable Curtailment	Renewable Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	Events Per Year	M$
2021 Base Case	17%/2,322	3%	0.83%	19,579	0.165	1.02	339.3
2021 Base Case	17%/2,322	5%	0.97%	22,833	0.141	0.25	343.6
2021 Base Case	17%/2,322	7%	1.11%	26,265	0.138	0.16	348.0

	BA Renewable Penetration/ PNM Renewable Gen	LF	Renewable Curtailment	Renewable Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	Events Per Year	M$
2024 SJ Retires	19%/2,714	3%	0.86%	23,800	0.095	1.74	473.5
2024 SJ Retires	19%/2,714	5%	0.98%	26,952	0.075	0.38	478.8
2024 SJ Retires	19%/2,714	7%	1.11%	30,453	0.072	0.1	483.9

[10] Renewable penetration is calculated as renewable generation divided by energy demand for the balancing area. The PNM Renewable represents the GWh of renewable generation. Both values are an average over the 36 weather years.

As the renewable penetration of the balancing area is increased to 40%, 50%, and 80%, load following targets must be increased substantially to avoid $LOLE_{FLEX}$. Table ES2 shows those results. Load following targets were increased from 7% of load to 17% or 18% of load in order to lower $LOLE_{FLEX}$ to reasonable levels. On average, this equates to 290 to 300 MW of online reserves to accommodate the renewable fleet. The renewable curtailment becomes a significant problem in the higher renewable penetration scenarios. System production costs are much higher as well due to all the renewable that is curtailed but still must be paid for based on an assumed PPA price. Also, to meet the higher load following requirements, the system fleet is forced to operate less efficiently causing costs to increase. Renewable curtailment increases to over 35% of the renewable fleet in the 80% renewable penetration scenario. Planning heuristics regarding $LOLE_{FLEX}$, renewable curtailment, and cost increases are included in the results section of the report.

Table ES2. Flexibility Metrics for Higher Renewable Penetration Levels

	BA Renewable Penetration/ PNM Renewable Gen	LF Target	Renewable Curtailment	Renewable Curtailment	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	M$
2024 SJ Retires	19%/2,322	7%	1.11%	30,453	0.1	483.91
2024 SJ Retires 40% RPS (66.7% Solar)	39%/5,544	17%	17.58%	981,443	0.17	545.17
2024 SJ Retires 40% RPS (66.7% Wind)	38%/5,493	17%	13.41%	741,718	0.06	535.31
2024 SJ Retires 50% RPS (66.7% Solar)	49%/7,038	17%	26.10%	1,847,546	0.33	576.25
2024 SJ Retires 50% RPS (66.7% Wind)	48%/6,960	17%	19.90%	1,393,006	0.22	559.21
2024 SJ Retires 80% RPS (66.7% Solar)	80%/11,519	18%	45.50%	5,258,862	1.64	717.79
2024 SJ Retires 80% RPS (66.7% Wind)	79%/11,360	18%	37.20%	4,241,265	1.33	678.87

Energy storage resources and quick start LM6000 resources were added to the system to determine their impact on reliability and costs. The results show that energy storage is not economic in the 2024 SJGS Retires Case with approximately 20% BA renewable penetration, but as the BA approaches 40% renewable penetration and higher, energy storage shows significant value ranging from \$160/kW-yr to \$250/kW-yr depending on the scenario and battery configuration. The value is driven primarily by two factors in the high renewable penetration cases: (1) shifting curtailed renewable energy from the middle of the day to later in the day when net load peaks and (2) batteries provide inexpensive load following. The energy storage analysis showed that energy beyond 4 hours of full dispatch capability did not provide significant benefit.

The quick start CT resources provide approximately $37/kW-yr in system production costs savings in the 2024 SJGS Retires Case and the higher renewable penetration cases simulated. Interestingly, the CT analysis demonstrates that without associated changes to operating guidelines, incremental flexible units with characteristics as modeled don't reduce $LOLE_{FLEX}$ significantly. The majority of $LOLE_{FLEX}$ events are typically less than 10 minutes in duration and caused when online reserves are insufficient to meet the rapid increase in net load. Since the CT that was modeled has a 10-minute startup time, it cannot ramp quickly enough to alleviate this issue and additional load following is still needed to provide relief to the situation.

In conclusion, Astrapé recommends targeting a specific reliability metric instead of a fixed reserve margin level since changes to market availability or even the fleet composition could change the relationship between reserve margin and reliability. The recommended metric is 0.2 LOLE which translates to a future minimum reserve margin of 17% for the PNM system. Even at a 17% reserve margin, there is still market assistance risk which could justify even a higher target. The current portfolio is reliable from a capacity and flexibility standpoint given a 7% load following target is utilized in real time operations in addition to a 4% regulation target. As renewable penetration increases, it is expected that renewable curtailment could be a significant problem and that solutions such as energy storage will be required. However, given the current portfolio which still includes significant conventional generation, the energy storage projects are likely not economic.

I. LIST OF FIGURES

II. LIST OF TABLES

III. INPUT ASSUMPTIONS

A. STUDY YEARS AND RESOURCE PLANS

The selected years for this study are 2021 and 2024, which represent years with significant amounts of renewable additions expected on the system. In the first scenario, San Juan 1 & 4 are retired in 2022 and the Palo Verde (PV) lease is included. The second scenario assumes SJGS continues and the PV lease is excluded. Data Center 1 load and resources are included in both portfolios which includes substantial renewable additions. Additional gas peaking capacity is also include in the plans. Table 1 shows the resource expansion plan used for the two scenarios.

Table 1. Expansion Plan

	2017 IRP ***SJGS Retires in 2022*** ***(PVNGS Lease Purchases)*** ***LOAD = MID, GAS = MID, CO2 = MID***	***2017 IRP*** ***SJGS Continues*** ***(No PVNGS Lease Purchases)*** ***LOAD = MID, GAS = MID, CO2 = MID***
Year	**Resource**	**Resource**
2018	Data Center1 Solar1 (30 MW) Data Center1 Wind1 (50 MW)	Data Center1 Solar1 (30 MW) Data Center1 Wind1 (50 MW)
2019	Data Center1 Solar2 (40 MW) Wind for RPS (50 MW)	Data Center1 Solar2 (40 MW) Wind for RPS (50 MW)
2020	Data Center1 Solar3 (30 MW) Data Center1 Wind2 (50 MW) Solar PV for RPS (49.5 MW)	Data Center1 Solar3 (30 MW) Data Center1 Wind2 (50 MW) Solar PV for RPS (49.5 MW)
2021	Data Center1 Solar4 (30 MW) Data Center1 Wind3 (50 MW)	Data Center1 Solar4 (30 MW) Data Center1 Wind3 (50 MW)
2022	Data Center1 Solar5 (40 MW) Data Center1 Wind4 (30 MW) Reciprocating Engines (41 MW)	Data Center1 Solar5 (40 MW) Data Center1 Wind4 (30 MW)
2023	Data Center1 Solar6 (20 MW) 2 x Large GT (374 MW) PVNGS U1 Lease Purchase (104 MW) Reciprocating Engines (41 MW)	Data Center1 Solar6 (20 MW) Large GT (187 MW)

2024	PVNGS U2 Lease Purchase (10 MW) Solar PV Large (50 MW)

In addition to these two scenarios another scenario was developed based on feedback from the Public Advisory Session in April of 2017. This portfolio retires San Juan, Four corners, and excludes the lease on Palo Verde 3. The expansion plan for this sensitivity is shown in Table 2.

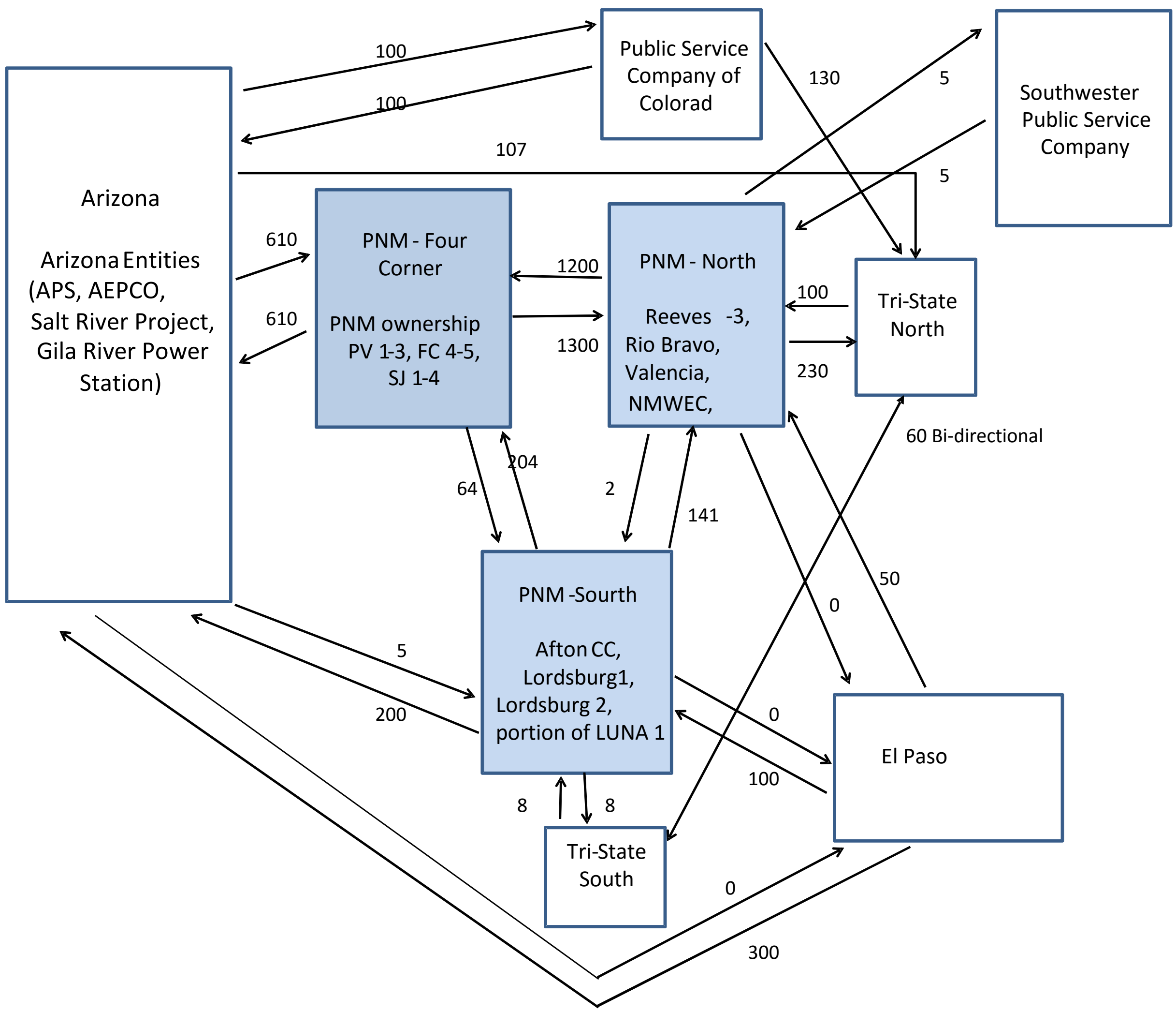
Table 2. Expansion Plan

	SJGS Retires in 2022; FC retires in2023 ***(No PVNGS Lease Purchases)*** ***LOAD = MID, GAS = MID, CO2 = MID***
Year	**Resource**
2018	Data Center1 Solar1 (30 MW) Data Center1 Wind1 (50 MW)
2019	Data Center1 Solar2 (40 MW) Solar PV for RPS (50 MW)
2020	Data Center1 Solar3 (30 MW) Data Center1 Wind2 (50 MW)
2021	Data Center1 Solar4 (30 MW) Data Center1 Wind3 (50 MW)
2022	Data Center1 Solar5 (40 MW) Data Center1 Wind4 (30 MW)
2023	1x1 NGCC (250 MW) Data Center1 Solar6 (20 MW) 2 x Large GT (374 MW)
2024	Large GT (187 MW)

B. STUDY TOPOLOGY

Figure 1 shows the study topology used in the analysis. To adequately understand system resource adequacy, it is important to capture the load diversity and generator outage diversity that a system has with its neighbors. For this study, the PNM system was divided into three regions: (1) PNM-North, (2) PNM-South, and (3) PNM-Four Corners. The surrounding regions captured in the modeling included all of the Arizona load serving entities, Public Service Company of Colorado, Tri-State Generation and Transmission Association, Southwestern Public Service Company, and El Paso Electric Company. For commitment and dispatch purposes, the PNM regions and Tri State regions were committed as one region to reflect the current balancing area makeup. In this commitment and dispatch of the PNM and Tri State regions, the transmission constraints were respected. All output results of the modeling reflect the PNM Balancing Area which includes the Tri State regions. All transmission input information was provided by PNM Transmission.

Figure 1. Study Topology



C. LOAD MODELING

Table 3 displays the PNM annual peak forecast for 2021 and 2024 under normal weather conditions.

Table 3. 2021 and 2024 Load Forecast

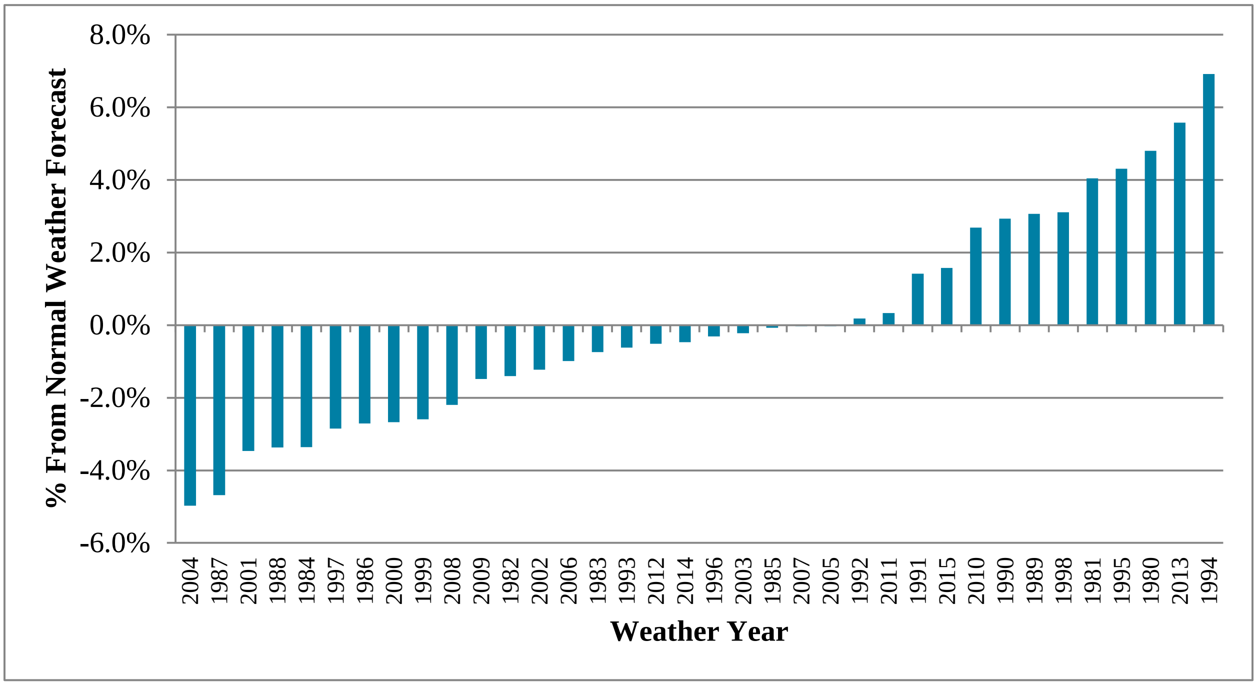
Year	Coincident System Peak (MW)	North Region Load (MW)	South Region Load (MW)
2021	1,999	1,871	128
2024	2,082	1,949	134

*EE and PV-DG removed the forecast

To model the effects of weather uncertainty, 36 historical weather years were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load, a neural network program was used to develop relationships between weather observations and load. Different relationships were built for each month. These relationships were then applied to the last 36 years of weather to develop 36 load shapes for 2021 and 2024. Equal probabilities were given to each of the 36 load shapes in the simulation. Figure 2 ranks all weather years by summer peak load and shows variance from normal weather. In the most severe weather conditions, the peak can be as much as 7% higher than under normal weather conditions.

Separate relationships were built for the North and South regions to ensure proper weather diversity was captured.

Figure 2. 2021 Peak Load Rankings for All Weather Years



Loads for each external region were developed in a similar manner as the PNM loads. A relationship between hourly weather and publicly available hourly load[11] was developed based on recent history, and then this relationship was applied to 36 years of weather data to develop 36 load shapes. Table 4 shows the resulting weather diversity between PNM-North and the other regions. When the PNM-North region is at peak load, the external regions are between 3% and 10% below their peak load on average over the 36-year period.

[11] FERC 714 Forms were accessed to pull hourly historical load for all neighboring regions.

Table 4. 2021 External Region Diversity

	PNM North	PNM South	Arizona Entities	EPE	PSCO	SWPSC	Tri-State North	Tri-State South
Average Non-Coincident Peak Load	1,906	129	18,801	1,956	6,270	5,142	295	159
Average Load when System is at Peak Load	1,811	118	18,478	1,822	5,945	4,807	279	136
Average Diversity	-5.0%	-8.3%	-1.7%	-6.9%	-5.2%	-6.5%	-5.4%	-14.5%
Average Load when PNM Balancing Area is at Peak Load	1,901	125	16,935	1,824	5,696	4,676	290	149
Average Diversity	-0.3%	-2.8%	-9.9%	-6.7%	-9.2%	-9.1%	-1.7%	-6.7%

D. ECONOMIC LOAD FORECAST ERROR

Economic load forecast error multipliers were developed to isolate the economic uncertainty that PNM has in its 4 and 5 year load forecasts. Based on reviewing Congressional Budget Office (CBO) GDP forecasts 4 years ahead and comparing those forecasts to actual data, a standard deviation was calculated and a normal distribution was developed for economic load forecast error. Because electric load grows at a slower rate than GDP, a 30% multiplier was applied to the raw CBO forecast error. Table 5 shows the economic load forecast multipliers and associated probabilities. The table shows that 2.7% of the time, it is expected that load will be under-forecasted by 5% four years out. The load forecast multipliers were applied to all regions. Within the simulations, when PNM under-forecasted load, the external regions also under-forecasted load. The SERVM model utilized each of the 36 weather years and applied each of these seven load forecast error points to create 252 different load scenarios. Each weather year was given equal probability of occurrence.

Table 5. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.95	2.7%
0.97	14.0%
0.99	23.8%
1.00	19.1%
1.01	23.8%
1.03	14.0%
1.05	2.7%

E. EXISTING THERMAL RESOURCES

The existing thermal resources included in the 2021 and 2024 study are shown in the following table. All input data was based on the most recent PROMOD simulations and interactions with PNM planning.

Table 6. Summary of Resources

Unit Name	Fuel Type	Capacity (MW)	Location
AFTON	Natural Gas	230	PNM-South
FOUR CORNERS 4	Coal	100	PNM-Four Corners
FOUR CORNERS 5	Coal	100	PNM-Four Corners
PALO VERDE 1	Uranium	134	PNM-Four Corners
PALO VERDE 2	Uranium	134	PNM-Four Corners
PALO VERDE 3	Uranium	134	PNM-Four Corners
REEVES 1	Natural Gas	44	PNM-North
REEVES 2	Natural Gas	44	PNM-North
REEVES 3	Natural Gas	66	PNM-North
SAN JUAN 1	Coal	170	PNM-Four Corners
SAN JUAN 4	Coal	327	PNM-Four Corners
RIO BRAVO 1	Natural Gas	132	PNM-North
VALENCIA	Natural Gas	158	PNM-North
LORDSBURG 1	Natural Gas	40	PNM-South
LORDSBURG 2	Natural Gas	40	PNM-South
LUNA 1	Natural Gas	190	PNM-South
LA LUZ	Natural Gas	40	PNM-North

To accurately reflect the flexibility of the PNM system, each resource was modeled with detailed heat rate curves, min-up and min-down times, startup times, and ramp rates. All constraints were respected by SERVM in the simulations and are shown in Table 7. All units except for Palo Verde 1-3 were allowed to serve regulating and spinning reserves. Only Lordsburg 1 and 2, and La Luz were able to serve non-spinning reserves.

Table 7. Resource Constraints

Unit Name	Capacity MW	Minimum Capacity MW	10 Min Ramping Capability MW	Min-up Time Hours	Min-down Time Hours	Startup Time Hours	Serve Regulation	Serve Quick Start (Non-Spin)
AFTON	230	160	80.9	4	4	3	Y	N
FOUR CORNERS 4	100	65	5.55	20	20	24	Y	N
FOUR CORNERS 5	100	65	5.55	20	20	24	Y	N
PALO VERDE 1	134	134	0	48	100	48	N	N
PALO VERDE 2	134	134	0	48	100	48	N	N
PALO VERDE 3	134	134	0	48	100	48	N	N
REEVES 1	44	9	20.9	3	3	2	Y	N
REEVES 2	44	90	19	3	3	2	Y	N
REEVES 3	66	13	26.4	3	3	2	Y	N
SAN JUAN 1	170	110	1.64	20	20	24	Y	N
SAN JUAN 4	327	115	27.2	20	20	24	Y	N
RIO BRAVO 1	132	80	52.8	2	2	0	Y	N
VALENCIA	158	66	13.1	4	3	0	Y	N
LORDSBURG 1	40	50	40	0	0	0	Y	Y
LORDSBURG 2	40	5	40	0	0	0	Y	Y
LA LUZ	40	5	40	0	0	0	Y	Y
LUNA 1	190	100	190	8	8	3	Y	N

From a cost standpoint, the following fuel prices, startup costs, and variable O&M costs were used for each unit for 2021. The final column shows the July dispatch price at max for 2021.

Table 8. Heat Rate and Cost Characteristics

Unit Name	July 2021 Fuel Price $/MMBtu	Startup Cost $/Start	Variable O&M $/MWh	Heat Rate at Max Btu/kWh	July Dispatch Price at Max Capacity $/MWh
AFTON	$4.33	$8,050	3.70	7.49	34.05
FOUR CORNERS 4	$2.73	$0	0	10.11	31.00
FOUR CORNERS 5	$2.73	$0	0	10.11	31.00
PALO VERDE 1	$1.12	$0	0	10.3	12.46
PALO VERDE 2	$1.12	$0	0	10.3	12.46
PALO VERDE 3	$1.12	$0	0	10.3	12.46
REEVES 1	$5.10	$0	1.00	10.75	45.18
REEVES 2	$5.10	$0	1.00	11.08	46.54
REEVES 3	$5.10	$0	1.00	11.00	46.23
SAN JUAN 1	$1.15	$0	1.01	10.29	15.00
SAN JUAN 4	$1.15	$0	1.01	10.35	15.00
RIO BRAVO 1	$5.10	$6,900	3.00	10.28	45.71
VALENCIA	$4.33	$7,250	6.98	10.56	49.89
LORDSBURG 1	$4.33	$0	5.50	9.60	44.38
LORDSBURG 2	$4.33	$0	5.50	9.58	44.29
LA LUZ	$4.33	$0	5.50	9.45	43.81
LUNA 1	$4.33	$0	7.56	7.41	31.70

F. UNIT OUTAGE DATA

Unlike typical production cost models, SERVM is not provided an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events are entered for each unit, and SERVM randomly draws from these events to simulate the unit outages. Historical events are entered using the following variables:

Full Outage Modeling

Time-to-Repair Hours

Time-to-Fail Hours

Partial Outage Modeling

Partial Outage Time-to-Repair Hours

Partial Outage Derate Percentage

Partial Outage Time-to-Fail Hours

Maintenance Outages

Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods

Planned Outages

Specific time periods are entered for planned outages. Typically these are performed during shoulder months.

As an example, assume that from 2013 through 2017, Four Corners 4 had 15 full outage events and 30 partial outage events reported in the GADs data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Since there typically is an improvement in EFOR across the summer, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, off peak, and winter based on history. Further, assume Four Corners 1 is online in hour 1 of the simulation. SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture.

The most important aspect of unit performance modeling in reliability studies is the cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Figure 3 shows the distribution of outages for the PNM Balancing area based on historical modeled outages. The figure demonstrates that in any given hour, the system can have between 0 and 1000 MW of its generators offline due to forced outages. The figure shows that in approximately 10% of all hours throughout the year, the balancing area has greater than 400 MW in a non-planned outage condition. This is typically comprised of several units that are on forced outage at the same time.

Figure 3. Conventional Resources on Forced Outage as a Percentage of Time

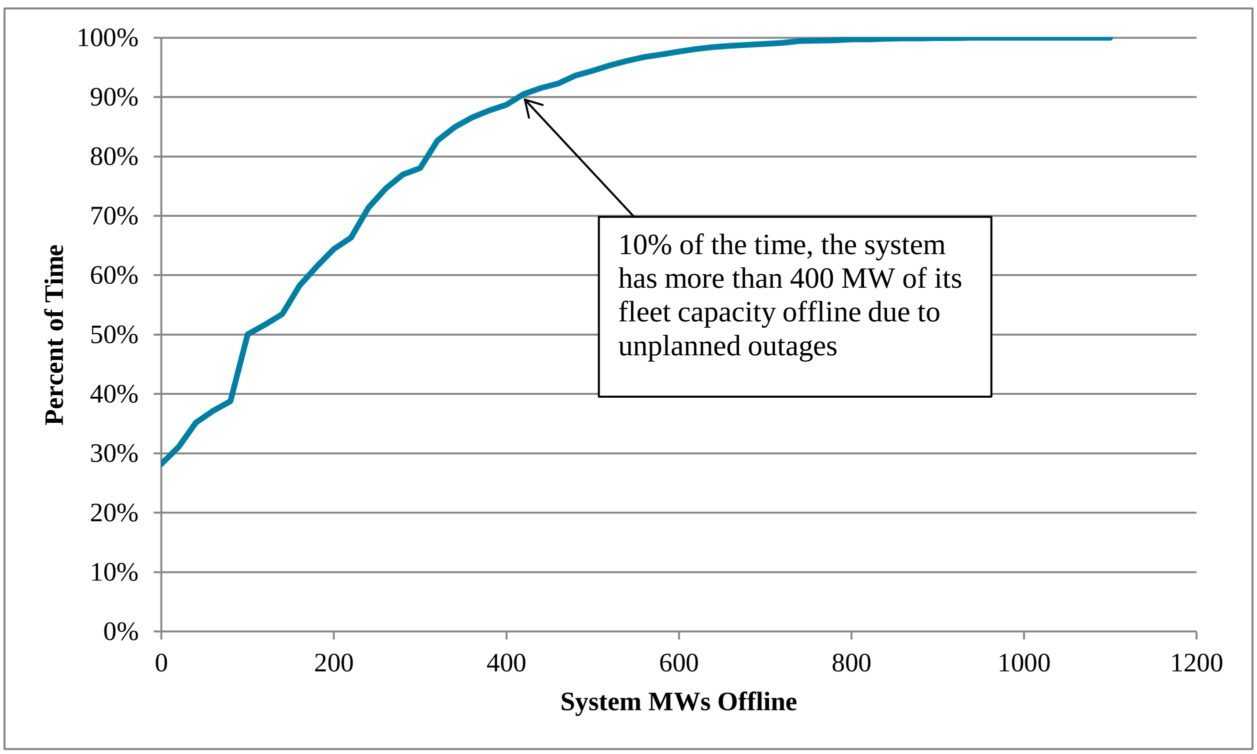


Table 9 shows modeled EFOR rates for each individual unit.

Table 9. Forced Outage Rate Data

Unit Name	Fuel Type	EFOR
AFTON	Natural Gas	4%
FOUR CORNERS 4	Coal	20%
FOUR CORNERS 5	Coal	20%
PALO VERDE 1	Uranium	2%
PALO VERDE 2	Uranium	2%
PALO VERDE 3	Uranium	2%
REEVES 1	Natural Gas	3%
REEVES 2	Natural Gas	2.27%
REEVES 3	Natural Gas	3%
SAN JUAN 1	Coal	17%
SAN JUAN 4	Coal	17%
RIO BRAVO 1	Natural Gas	3%
VALENCIA	Natural Gas	3%
LORDSBURG 1	Natural Gas	3%
LORDSBURG 2	Natural Gas	3%
LA LUZ	Natural Gas	3%
LUNA 1	Natural Gas	4%

Planned maintenance rates for 2021 and 2024 are shown in Table 10.

Table 10. Planned Maintenance Rates

Unit	Days	Rate
AFTON	35	10%
FOUR CORNERS 4	12	3%
FOUR CORNERS 5	8	2%
PALO VERDE 1	0	0%
PALO VERDE 2	35	10%
PALO VERDE 3	35	10%
REEVES 1	12	3%

REEVES 2	12	3%
REEVES 3	12	3%
SAN JUAN 1	0	0%
SAN JUAN 4	28	8%
RIO BRAVO 1	12	3%
VALENCIA	12	3%
LORDSBURG 1	4	1%
LORDSBURG 2	4	1%
LA LUZ	4	1%
LUNA 1	8	2%

G. RENEWABLE RESOURCE MODELING

Table 11 shows the solar resources that were captured in the study along with the capacity credit assigned to each resource for reserve margin calculation purposes only.

Table 11. Solar Resources

Projects	Total (MW)	COD	PV Technology	Capacity Credit for Reserve Margin Calculations
ABQ Solar	2	4/8/2011	Fixed Tilt	55%
Los Lunas I	5	6/1/2011	Fixed Tilt	55%
Deming	5	8/3/2011	Fixed Tilt	55%
Alamogordo	5	10/14/2011	Fixed Tilt	55%
Las Vegas (Gallinas)	5	11/24/2011	Fixed Tilt	55%
Manzano	8	10/18/2013	Fixed Tilt	55%
Los Lunas II	2	10/17/2013	Fixed Tilt	55%
Deming II	4	11/8/2013	Fixed Tilt	55%
Otero	7.5	12/10/2013	Fixed Tilt	55%
Prosperity	0.5	10/25/2011	Fixed Tilt	55%
Sandoval County	8	2015	Single Axis Tracking	68%
Meadowlake	9	2015	Single Axis Tracking	68%
Cibola County	6	2015	Single Axis Tracking	68%
Solar PV Tier 1	40	2016	Single Axis Tracking	76%

New Projects	Total (MW)	COD	Technology	
Data Center 1 Solar 1 30 MW	30	2018	Single Axis Tracking	76%
Data Center 1 Solar 2 40 MW	40	2019	Single Axis Tracking	76%
Solar PV 2016 RFP	49.5	2020	Single Axis Tracking	35%
Data Center 1 Solar 3 30 MW	30	2020	Single Axis Tracking	76%
Data Center 1 Solar 4 30 MW	30	2021	Single Axis Tracking	76%
Data Center 1 Solar 5 40MW	40	2022	Single Axis Tracking	76%
Data Center 1 Solar 6 20MW	20	2023	Single Axis Tracking	76%
Solar PV Large	50	2024	Single Axis Tracking	35%

Total by 2024	396.5*

*Including Tri-State, there is a total of 451.5 MW of solar in the PNM balancing area

Solar shapes were developed from data downloaded from the National Renewable Energy Laboratory ("NREL") National Solar Radiation Database ("NSRDB") Data Viewer. Data was available for the years 1998 through 2014. Data was downloaded from 6 different cities within the PNM balancing area and the projects were matched with a city for modeling purposes. Historical solar data from the NREL NSRDB Data Viewer included variables such as temperature, cloud cover, humidity, dew point, and global solar irradiance. The data obtained from the NSRDB Data Viewer was then used as an input into NREL's System Advisory Model ("SAM") for each year and city to generate the hourly solar profiles based on the solar weather data for both a fixed solar photovoltaic (PV) plant and a tracking solar PV plant. Inputs in SAM included the DC to AC ratio of the inverter module and the tilt and azimuth angle of the PV array. Data was normalized by dividing each point by the input array size of 4,000 kW DC. Solar profiles for 1980 to 1998 were selected by using the daily solar profiles from the day that most closely matched the total load out of the corresponding data for the days that we had for the 17-year interval. The profiles for the remaining years 1998 to 2014 came directly from the normalized raw data. Figure 4 shows the average output by hour of day for one of the city's fixed and tracking profiles.

Figure 4. Average Solar Profile by Month

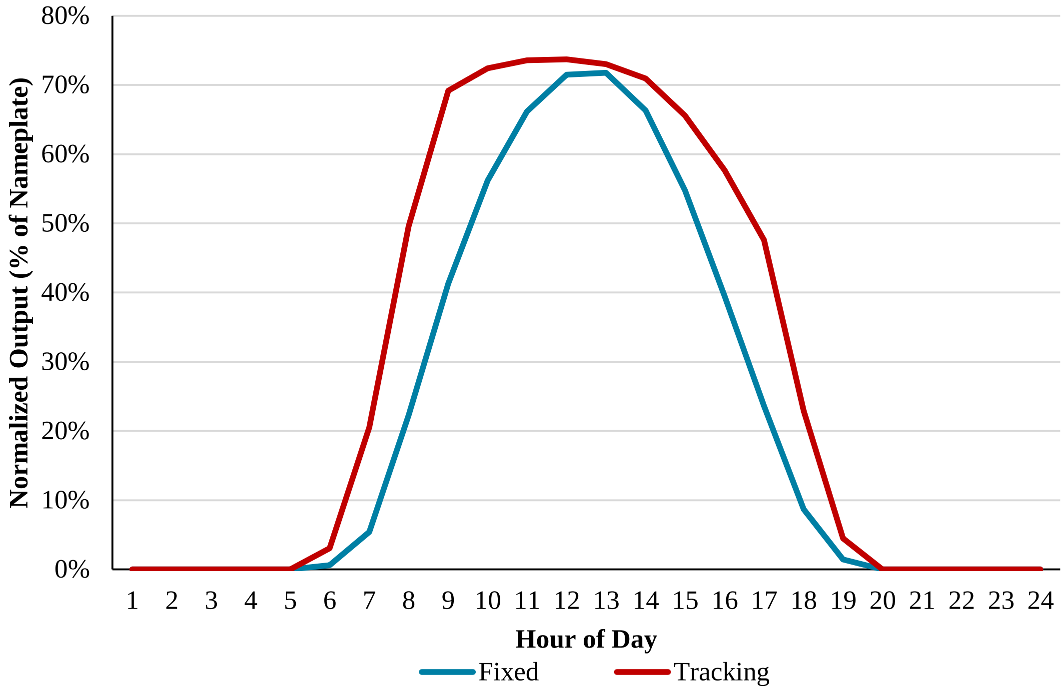


Table 12 displays the wind resources modeled in the study.

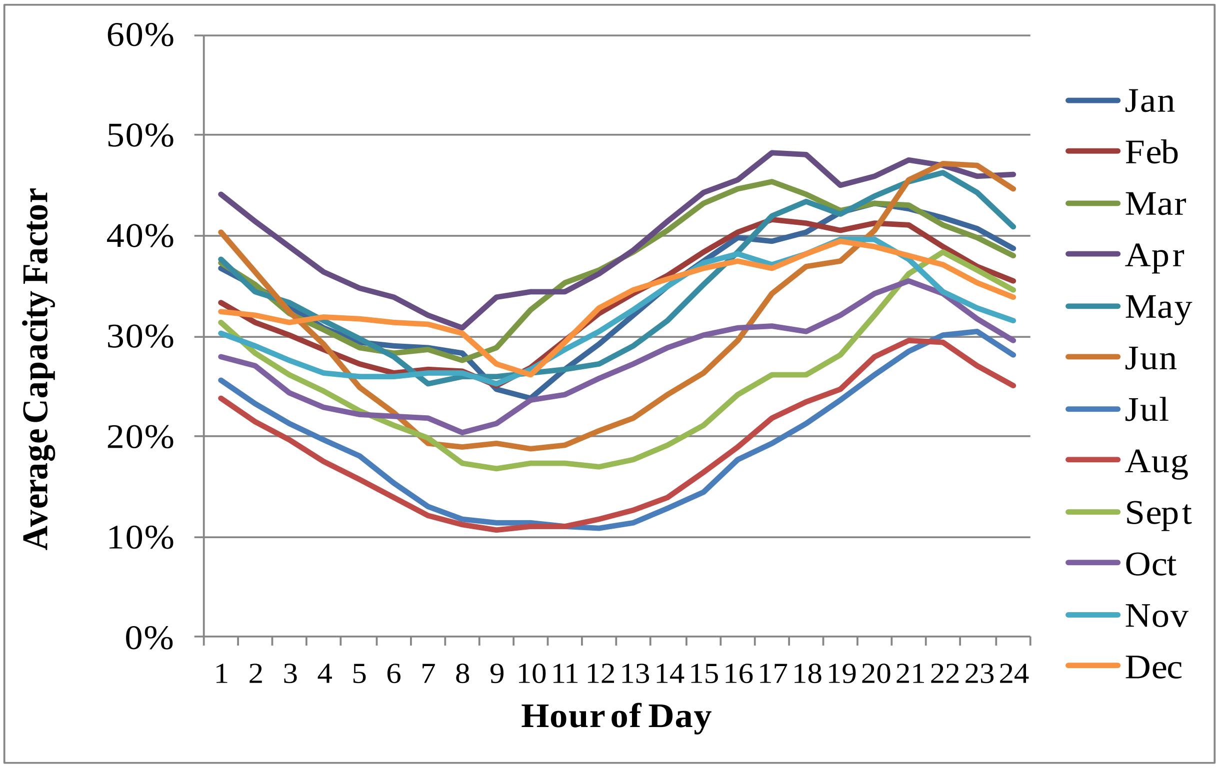
Table 12. Wind Resources

Projects	Total (MW)	COD
NWWEC	200	2000
Red Mesa	102	2011
2016 RFP Wind PPA 50 MW	50	2018
Data Center 1 Wind 1 50 MW	50	2018
Data Center 1 Wind 2 50 MW	50	2020
Data Center 1 Wind 3 50 MW	50	2021
Data Center 1 Wind 4 30 MW	30	2022
Total by 2021	501.2	
Total by 2024	531.2	

For the wind resources, 5 years of hourly data was available from the NM Wind Energy Center and Red Mesa wind projects. Based on the raw data, there was little to no correlation with load or weather variables. Therefore, instead of developing a weather/wind shape relationship, Astrapé used the 5 years of data and allowed the model to randomly draw days from those years. The draws were done by season and load level. For example, in July during a peak load period, the model draws from daily historical July shapes when load is above a specific threshold. By performing the wind modeling in this manner, we ensured that our capacity factors and wind output from hour to hour reflect historical profiles[12]. Figure 5 shows the average profiles by hour of day and month.

[12] If Astrapé had instead attempted to develop a neural net system for the weather to wind relationship, it is likely that the profiles would have not reflected the hour to hour movement that was seen in history which is important in system flexibility analysis.

Figure 5. Average Wind Profiles by Month



The 10 MW geothermal resource was treated as a must run resource for this study.

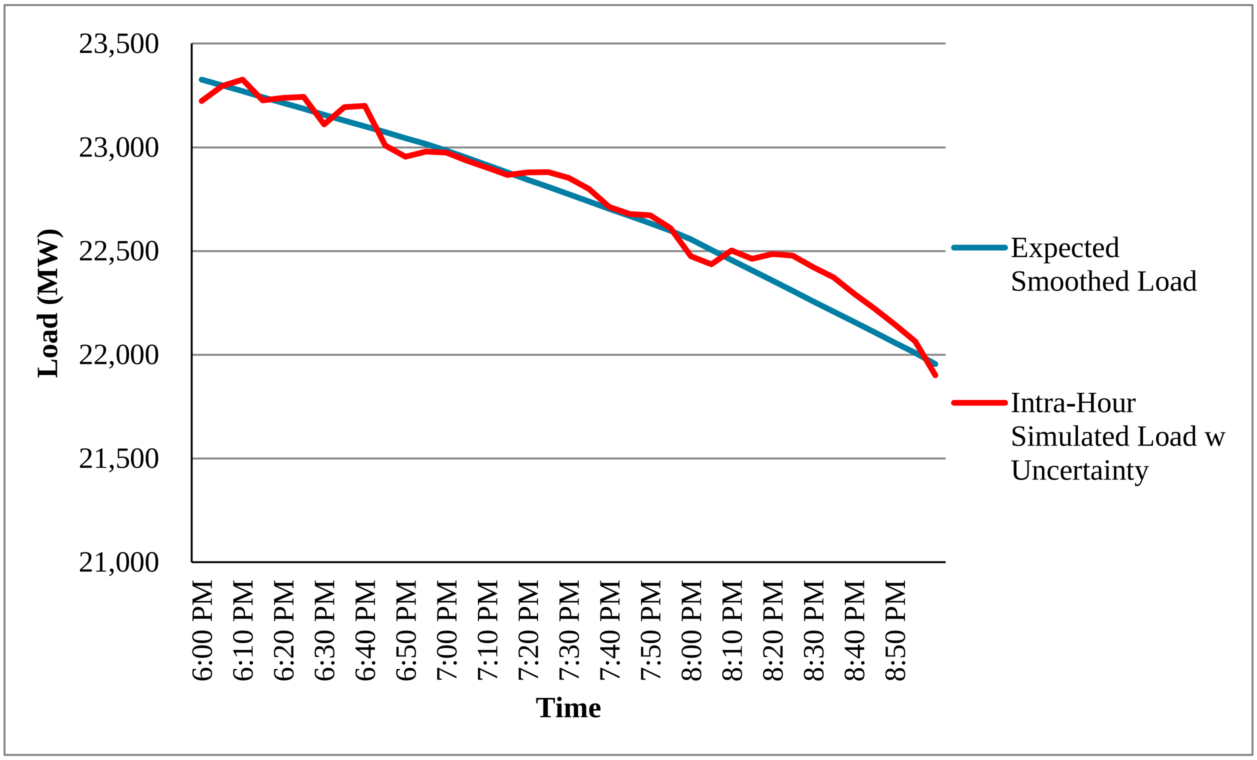
H. LOAD, WIND, AND SOLAR UNCERTAINTY DEVELOPMENT

For purposes of understanding the economic and reliability impacts of renewable profile uncertainty, we capture the implications of unpredictable intra-hour volatility. To develop data to be used in the SERVM simulations, Astrapé used 2016 five-minute data for solar resources, wind resources, and load. Within the simulations, SERVM commits to the expected net load and then has to react to intra hour volatility as seen in history.

Intra-Hour Forecast Error and Volatility

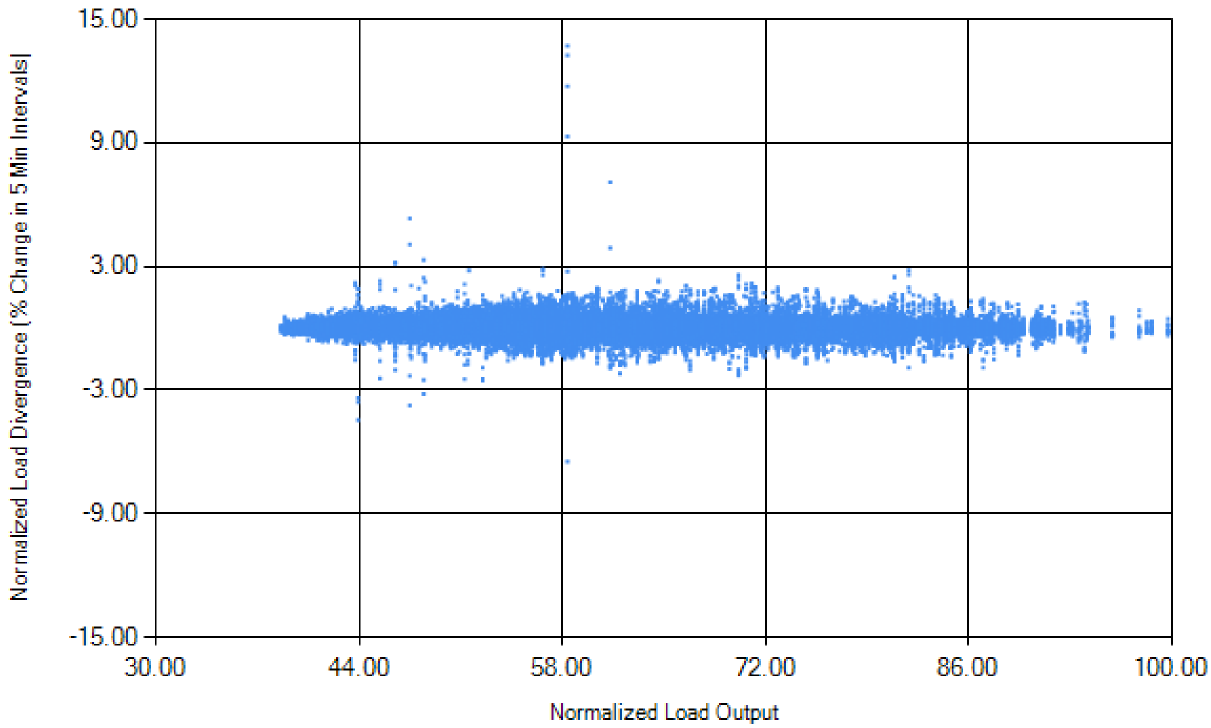
Within each hour, all three components of net load (load, wind, and solar), can move unexpectedly due to both natural variation and forecast error. SERVM attempts to replicate this uncertainty, and the conventional resources must be dispatched to meet the changing net load patterns. An example of the volatile net load pattern compared to a smooth intra-hour ramp is shown in Figure 6.

Figure 6. Volatile Net Load vs. Smoothed Net Load



The intra-hour distributions of variation used in the simulation are shown in Figures 7 - 9. The 5 minute variability in load is quite low ranging mostly between +/-3% on a normalized basis.

Figure 7. Load Intra-Hour Variation



The variability of solar and wind is much higher ranging from +/-20% with the majority movements ranging between +/-7%. The system must have enough online reserves to cover these 5 minute moves as all quick start capacity still requires 10 minutes for startup.

Figure 8. Solar Intra-Hour Variation

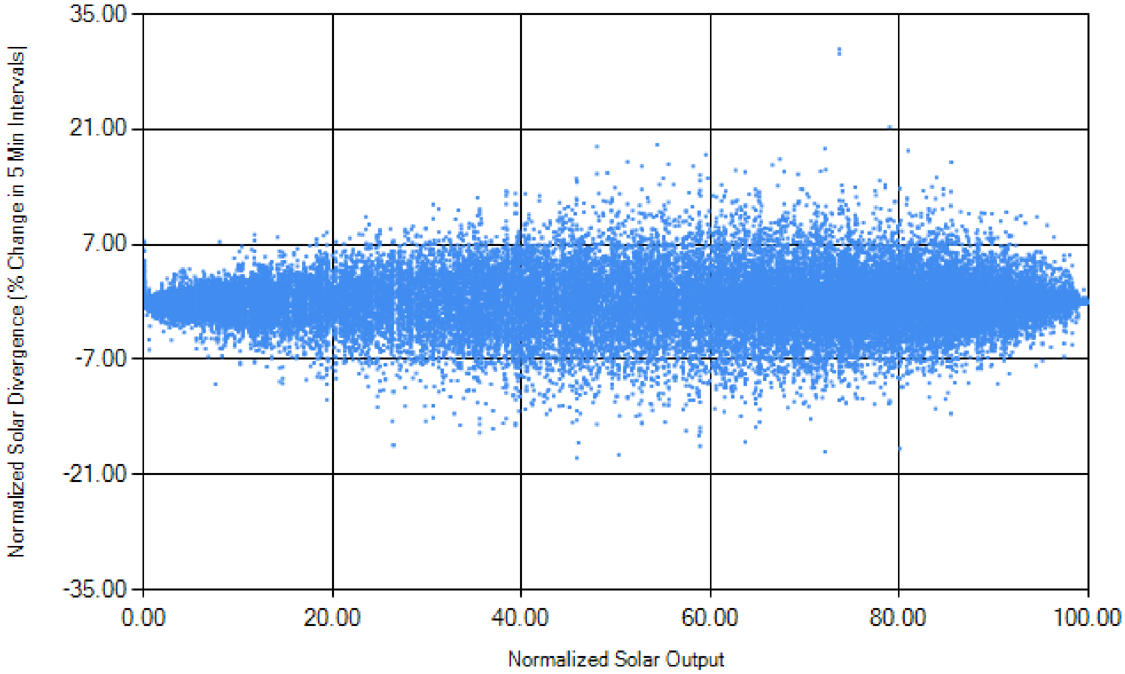
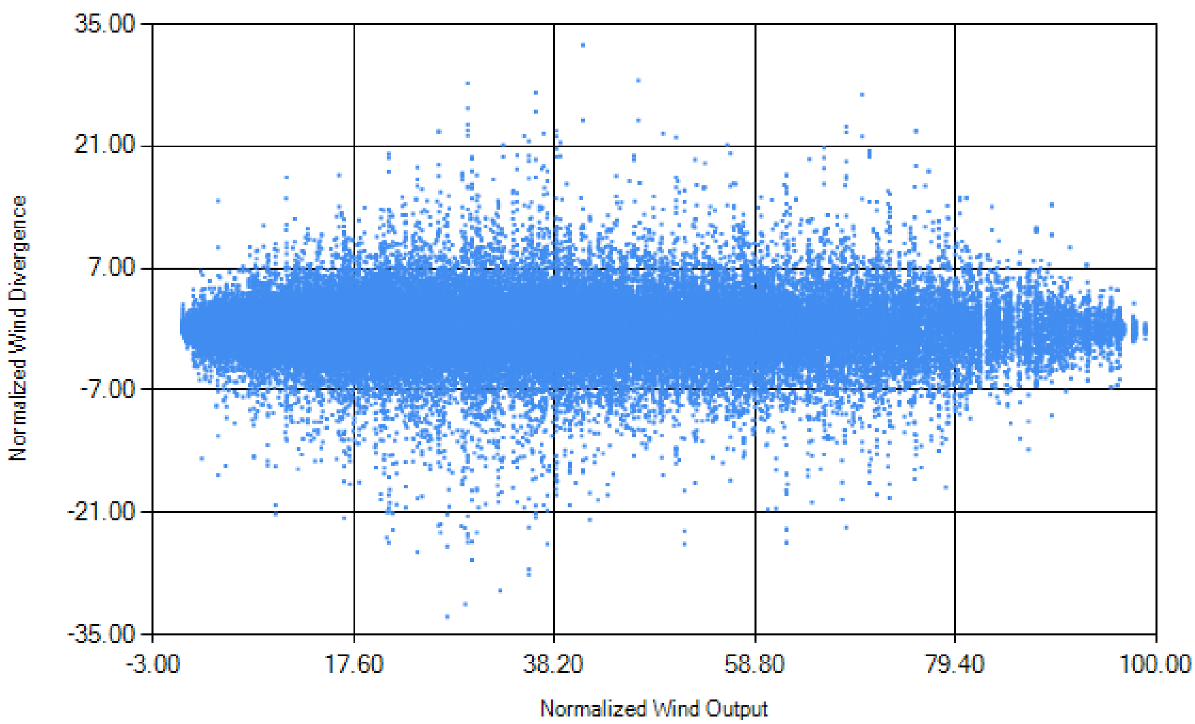


Figure 9. Wind Intra-Hour Variation



I. DEMAND RESPONSE MODELING

Demand response programs are modeled as resources in the simulations. They are modeled with specific contract limits including seasonal capability, hours per year, and hours per day constraints. Table 13 shows a breakdown of the Demand Response modeled in the Study. The resources are called when temperatures in the region meet a specific threshold. For the modeling, Astrapé and PNM agreed to set the dispatch of these resources where they would be called on average 50 hours per year but would be available for all hours of every summer.

Table 13. Demand Response Resources

	Power Saver Program	Peak Saver Program
Capacity (MW)	53.75	20
Season	June-Sept	June-Sept
Hours Per Year	100	100
Hours Per Day	4	6

J. 2021 AND 2024 LOAD/RESOURCE SUMMARY

Table 14 shows the load and resource summary for both study years for the PNM balancing area. All Distributed Generation (DG) PV is removed from load in the calculations, however, the DG PV was modeled as a resource in the simulations. The renewable values represent their appropriate capacity values and not nameplate values.

Table 14. PNM Balancing Area Load and Resources

Region	PNM	PNM	PNM
	Current Portfolio	SJGS Retires	SJGS Continues
Year	2021	2024	2024
Summer Peak Load	2,434	2,515	2,515
Nuclear Resources	402	402	298
Coal/Combined Cycle	1,472	975	1,472
Peaking Resources	724	1,182	913
Demand Response Resources	54	54	54
Renewable Resources	241	302	285
Total Resources	2,893	2,915	3,022
Reserve Margin	18.8%	15.9%	20.2%

Notes: Includes Tri -State Load and Resources

- Reserve Margin = (Resources – Demand) / Demand
  - Demand is the Annual Peak Load Forecast.
  - Demand response programs are included as resources and not subtracted from demand.
  - Wind resources are counted as 5% of nameplate capacity and PV resources are counted based on the capacity credit shown in Section G.

K. EXTERNAL MARKET MODELING

For a utility the size of PNM, the market plays a significant role in economic and reliability results. If several of PNM's large generators were experiencing an outage at the same time (even if loads weren't extremely high), and PNM did not have access to surrounding markets, there is a high likelihood of unserved load. The market representation used in SERVM was developed through consultation with PNM staff, FERC Forms, EIA Forms, and reviews of IRP information from neighboring regions. Table 15 shows the breakdown of capacity for each external region captured in the modeling. Each external region was modeled near its target reserve margin based on publicly available IRP information. While it is expected that reserves could be higher than this in the short term, it is not appropriate to incorporate such an assumption since it would represent an ability of PNM to lean heavily on external regions to meet reserve margin assuming that these external regions would have excess capacity perpetually. By setting the study up this way, only weather diversity and generator outage diversity are being captured amongst neighboring utilities.

Table 15. External Regions

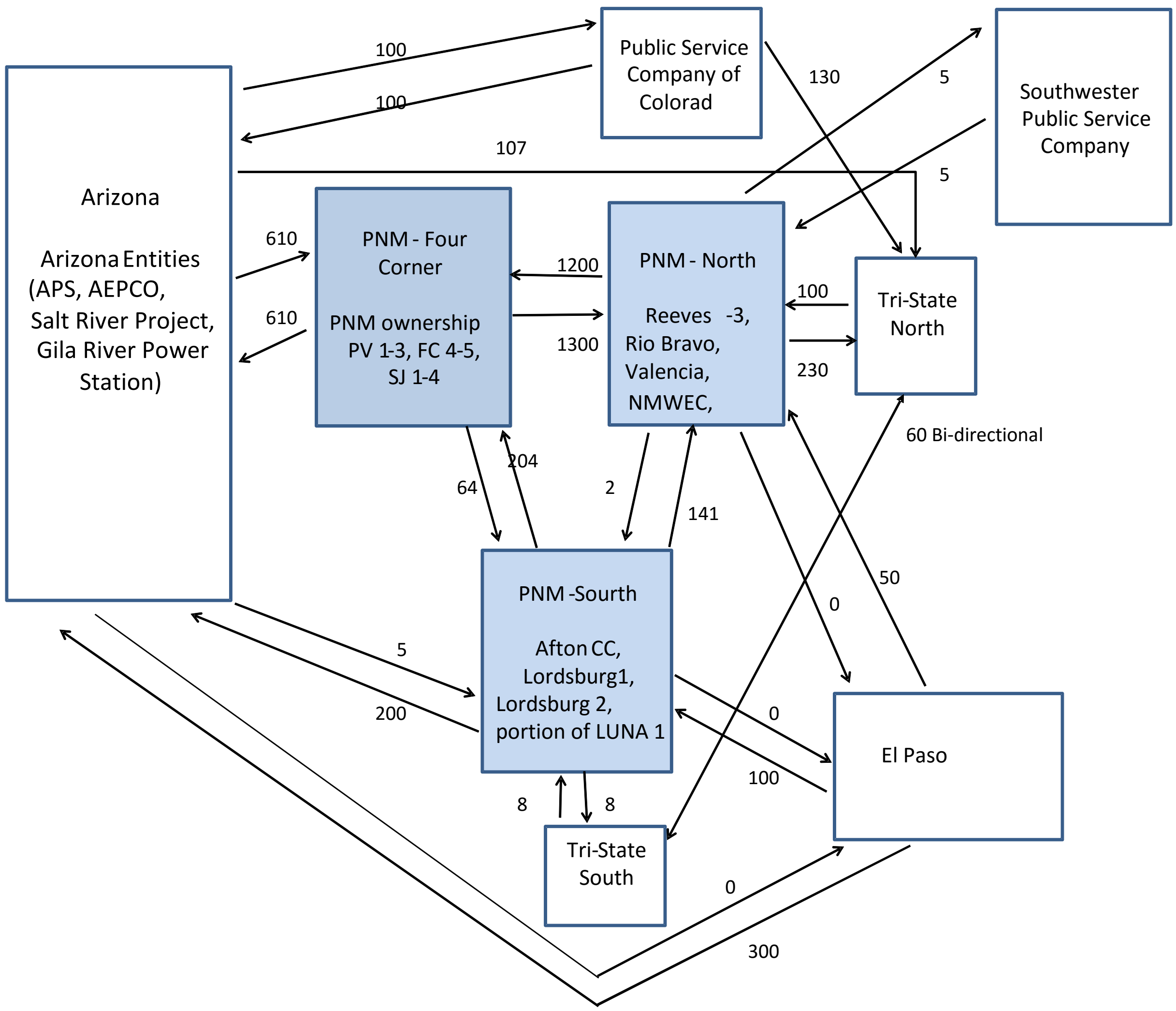
	Arizona Entities	EPE	PSCO	SWPSC
Summer Peak Load Forecast (MW)	18,800	1,956	6,270	5,147
Target RM*	15%	15%	13.40%	14%
Nuclear	1,824	624	0	0
Coal/Combined Cycle	14,705	369	5,265	2,765
Peaking	3,991	1,233	1,519	2,982
Pump Storage	176	0	162	0
Hydro	0	0	0	0
PV	1,200	0	0	0
Wind	0	0	2,100	1,250
DR	165	30	63	51
Total Capacity	22,061	2,256	9,109	7,048

*Reserve Margins assume 55% capacity credit for solar and 5% capacity credit for wind

The study topology including transmission capability is shown in Figure 10. The SERVM model dispatches each region's resources to load and then allows regions to share energy on an hourly basis based on economics but subject to transmission constraints. Changes in energy purchases are not allowed intra-hour. Regulating and spinning reserves are not allowed to be purchased from external regions but the additional hourly energy purchased allows for PNM to lower the dispatch of its own units to serve these ancillary services. Given the deficiency in load side generation in the PNM–North region, a substantial amount of energy will be transferred from the Four Corners Region and PNM–South. For these purposes, SERVM allows the PNM balancing area to be committed and dispatched together to a common system load. This includes PNM-North, PNM-Four Corners, PNM-South, Tri-State North, and Tri-State South. Then this smaller system can purchase and sell resources to the external region as appropriate.

It is obvious that the transmission is constrained within the balancing area and from outside the balancing area. As the location of additional conventional or renewable generation is not located in the PNM-N or PNM-S regions, the reliability results of this study are impacted in a negative way.

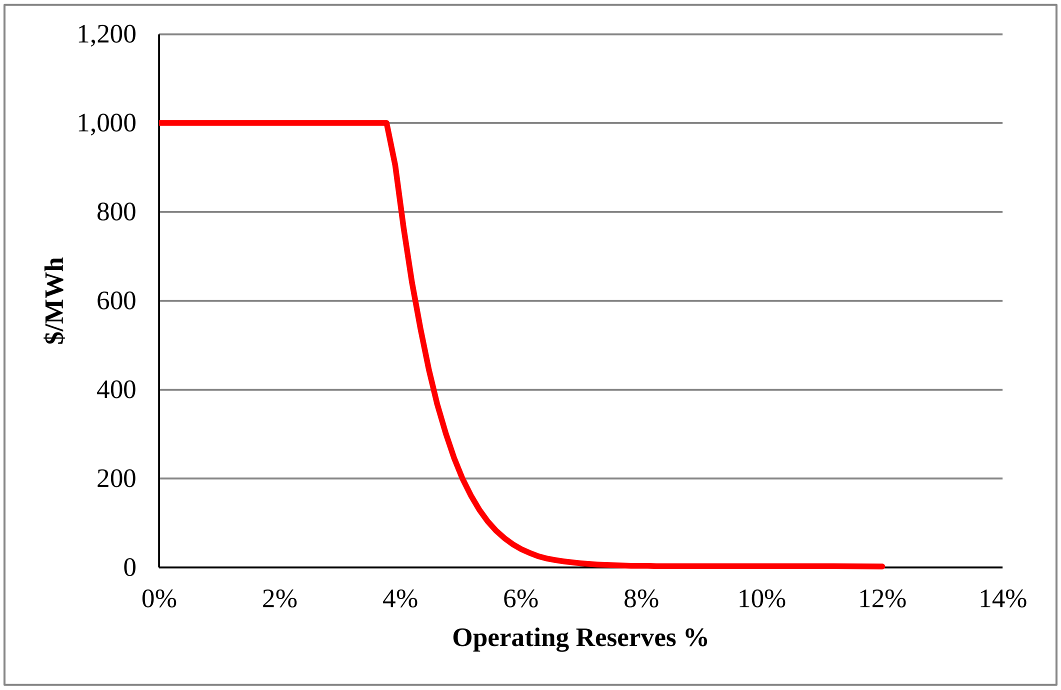
Figure 10. Study Topology with Transmission Limits



*All transmission constraints are in MW

The transfers within the PNM balancing area were based on the production cost of the resources. The cost of transfers between external regions and PNM are based on marginal costs with a $10/MWh profit margin. In cases where a region is short of resources, scarcity pricing is added to the marginal costs. As a region's hourly reserve margin approaches zero, the scarcity pricing for that region increases. Figure 11 shows the scarcity pricing curve that was used in the simulations. It should be noted that the frequency of these scarcity prices are very low because in the majority of hours, there is plenty of capacity to meet load after the market has cleared[13].

Figure 11. Scarcity Pricing Curve



L. ANCILLARY SERVICE REQUIREMENTS

For this study, three distinct ancillary services were modeled: Regulating Reserves, Spinning Reserves, and Non-Spinning Reserves. Traditional contingency reserves are defined as spinning and non-spinning reserves. Four percent of load was required for 10 min regulating reserves at all times, which equates to 100 MW during peak conditions and 60 MW on average. Only units with Automatic Generation Control (AGC) can serve this need. Firm load would be shed to maintain this regulation requirement. The spinning requirement was varied from three percent of load to seven percent of load to understand the impact additional spin has on reliability. SERVM commits enough resources to

[13]The market clearing algorithm within SERVM attempts to get all regions to the same price subject to transmission constraints and the $10/MWh profit margin. If a region's original price is $1,000/MWh based on the conditions and scarcity pricing in that region alone, it is highly probable that a surrounding region will provide enough capacity to that region to bring prices down to reasonable levels.

meet this requirement, but in the scenario where resources are not available, the spinning requirement can be reduced to zero. The non-spin requirement was set to 4% of load.

M. COST OF UNSERVED ENERGY

Unserved energy costs were derived based on information from national studies completed for the Department of Energy in 2003[14] and 2009[15] along with three other studies performed previously by different consultants. The national studies were compilations of other surveys performed by utilities over the last two decades. All studies split the customer class categories into residential, commercial, and industrial. The values were then applied to the actual PNM customer class mix to develop system unserved energy cost values. Table 16 shows those results. The final results were escalated at 2% per year to 2021 dollars for purposes of this study. Expected unserved energy costs are also a very small percentage of total system costs near the economic optimum reserve margin.

Table 16. Unserved Energy Costs

	Weightings	2003 DOE Study 2018 $/kW-yr	2009 DOE Study 2018 $/kW-yr	Christiansen Associates 2018 $/kW-yr	Billinton and Wacker 2018 $/kW-yr	Karuiki and Allan 2018 $/kW-yr
Residential	45%	1.55	0.54	3.32	2.91	1.34
Commercial	46%	88.83	78.58	23.83	24.77	26.37
Industrial	9%	29.61	7.25	12.35	24.77	62.5
Weighted Average $/kWh		43.91	36.71	13.5	14.9	18.42
Average $/kWh		25.49				

[14] http://certs.lbl.gov/pdf/54365.pdf
[15] http://certs.lbl.gov/pdf/lbnl-2132e.pdf

N. COST OF RENEWABLE CURTAILMENT

For this study, the cost of renewable curtailment was assumed to be equal to the PPA price for wind and solar energy which was approximately $40/MWh.

IV. SERVM MODEL AND METHODOLOGY

The SERVM Model is a chronological generation commitment and dispatch model that allows users to simulate electric systems down to 1 minute intervals taking into account all unit constraints while co-optimizing energy and ancillary services. Many planning models do not take into account all unit constraints and do not dispatch on a chronological basis, all which is essential in understanding intra hour system flexibility and renewable integration costs. SERVM outputs both physical reliability metrics such as $LOLE_{CAP}$ and $LOLE_{FLEX}$ as well as total system balancing area costs of every scenario simulated. When SERVM commits and dispatches resources to net load, it doesn't have perfect knowledge of the load and renewable profiles on a five minute interval. SERVM is used by entities across the U.S. including the Southern Company, TVA, Duke Energy, ERCOT, Pacific Gas & Electric, and the California Public Utilities Commission for resource adequacy and renewable integration analysis. Because of its rapid commitment and dispatch engine, it is able to simulate thousands of iterations varying load, generator outages, and renewable profiles across a multi area topology. Since most reliability events are high impact, low probability events, evaluating thousands of iterations is essential. As discussed previously, SERVM utilized 36 years of historical weather and load shapes, 7 points of economic load growth forecast error, and 10 iterations of unit outage draws for each scenario to represent the full distribution of realistic scenarios. The number of yearly simulation cases equals 36 weather years * 7 load forecast errors * 10 unit outage iterations = 2,520 total iterations for each scenario modeled. The 2,520 iterations represent full year simulations at 5 minute intervals.

An example of probabilities given for each case is shown in Table 17. Each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

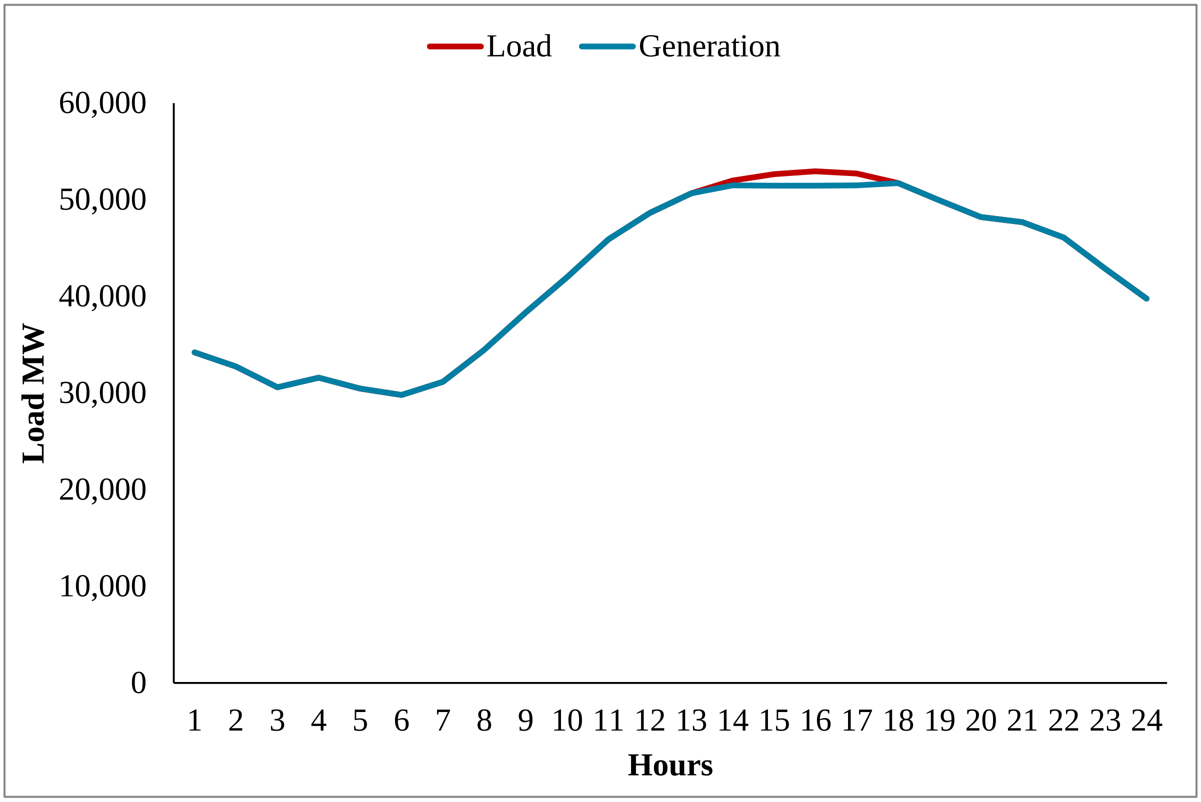
Table 17. Case Probability Example

Weather Year	Weather Year Probability	Load Multipliers due to Load Forecast Error	Load Multiplier Probability	Case Probability
1980	3.03%	95%	2.70%	0.082%
1980	3.03%	97%	14.00%	0.424%
1980	3.03%	99%	23.80%	0.721%
1980	3.03%	100%	19.00%	0.576%
1980	3.03%	101%	23.80%	0.721%
1980	3.03%	103%	14.00%	0.424%
1980	3.03%	105%	2.70%	0.082%
1981	3.03%	95%	2.70%	0.082%
1981	3.03%	97%	14.00%	0.424%
1981	3.03%	99%	23.80%	0.721%
1981	3.03%	100%	19.00%	0.576%
1981	3.03%	101%	23.80%	0.721%
1981	3.03%	103%	14.00%	0.424%
1981	3.03%	105%	2.70%	0.082%

For each case, and ultimately each iteration, SERVM commits and dispatches resources to load and ancillary service requirements by region on a 5-minute basis. As discussed in the load and renewable uncertainty sections, SERVM does not have perfect knowledge of the load or renewable resource output as it determines its commitment. SERVM begins with a week-ahead commitment, and as the prompt hour approaches the model is allowed to make adjustments to its commitment as units fail and more certainty around load and renewable output is gained. Ultimately, SERVM forces the system to react to these uncertainties while maintaining all unit constraints such as ramp rates, startup times, and min-up and min-down times. During each iteration, Loss of Load Expectation (LOLE) is calculated and the model splits LOLE into two categories based on the definition outlined in the following paragraph: (1) $LOLE_{CAP}$ and (2) $LOLE_{FLEX}$.

(1) $LOLE_{CAP}$: number of loss of load events due to capacity shortages, calculated in events per year. Figure 12 shows an example of a capacity shortfall which typically occurs across the peak of a day.

Figure 12. $LOLE_{CAP}$ Example



The industry standard is to maintain 1 $LOLE_{CAP}$ event every 10 years which is equivalent to 0.1 $LOLE_{CAP}$ per year. As discussed in the 2013 RM Study, a utility the size of PNM will have difficulty meeting 0.1 $LOLE_{CAP}$ due simply to the fact that it's largest single contingency is 13% of its peak load (327 MW/2,432 MW of load) versus a 20,000 MW load system whose largest unit (1,000 MW) only makes up 5% of its peak load.

(2) $LOLE_{FLEX}$: number of loss of load events due to system flexibility problems, calculated in events per year. In other words, there was enough capacity installed but not enough flexibility to meet the net load ramps, or startup times prevented a unit coming online fast enough to meet the unanticipated ramps.

Figures 13 and 14 shows $LOLE_{FLEX}$ examples. Figure 13 shows a multi hour ramping problem in which load could not be met whereas Figure 14 shows an intra hour ramping problem. Both of these loss of load events are categorized as $LOLE_{FLEX}$ events. The vast majority of $LOLE_{FLEX}$ events fall under the intra hour problems seen in Figure 14. These events are typically very short in duration and are caused by a rapid decline in solar or wind resources over a short time interval.

Figure 13. Multi Hour $LOLE_{FLEX}$

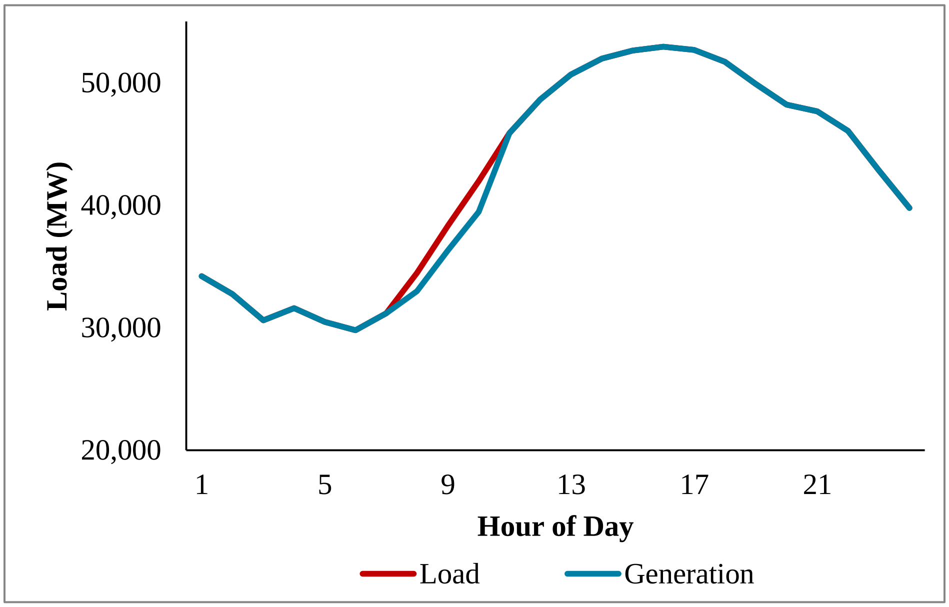
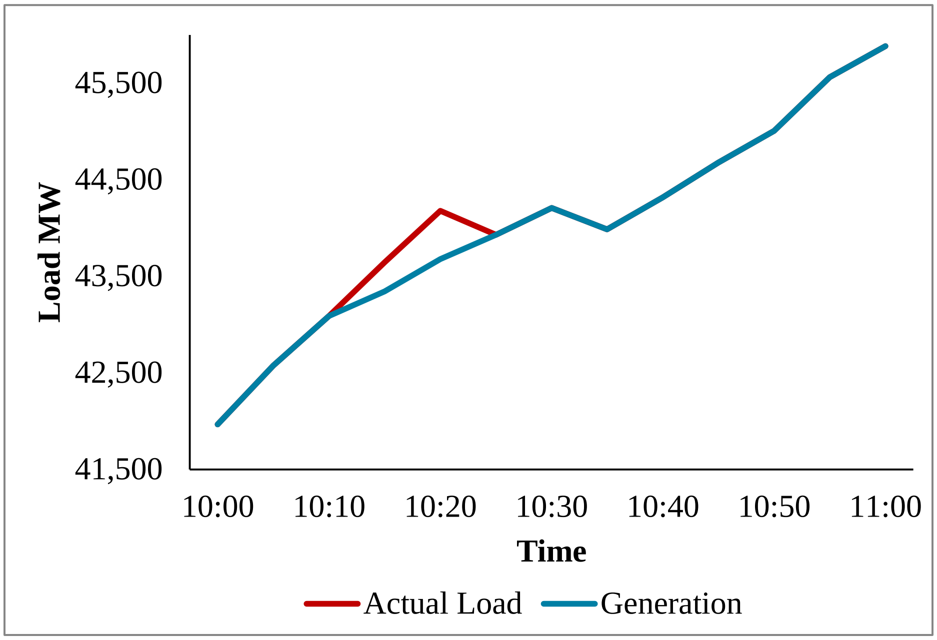


Figure 14. Intra Hour $LOLE_{FLEX}$



This is a new metric introduced by SERVM so no industry standard is currently set to capture reliability due to flexibility issues. Generally, these type of flexibility events are short, less than an hour, and low in magnitude compared to traditional $LOLE_{CAP}$ events.

Other key metrics recorded for each iteration are (3) renewable curtailment and (4) total costs.

(3) Renewable curtailment: Renewable curtailment occurs during over-generation periods when the system cannot ramp down fast enough to meet net load.

(4) Total PNM Balance Area Costs: Production costs + Purchase Costs - Sales Revenue + Expected Unserved Energy Costs

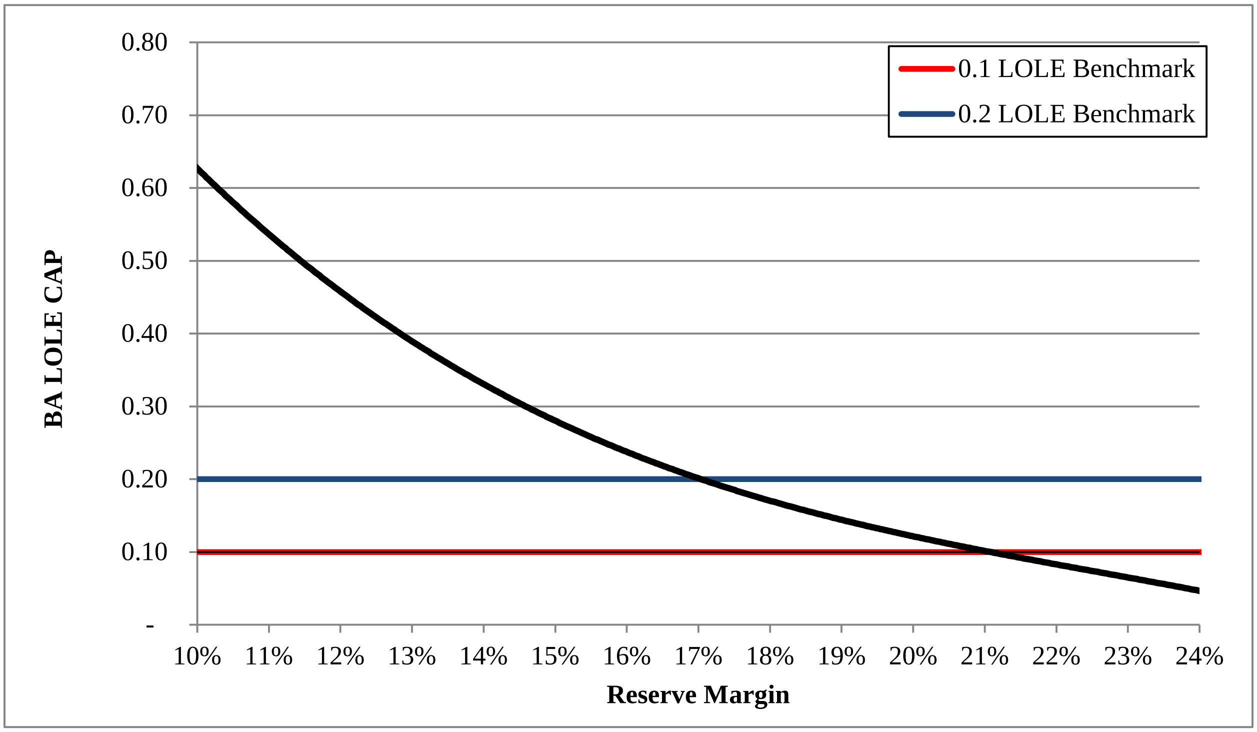
These reliability and cost components are calculated for each of the 252 cases and weighted based on probability to calculate an expected total cost for each study simulated. Production costs include all fuel burn , variable O&M, startup costs, and CO_2 costs. Costs for renewable generation are based on Power PPA pricing.

Purchase costs represent any costs for purchases of power from external entities while sales revenue includes any sales to external entities. Expected unserved energy costs includes all the firm load shed events which are priced at the cost of unserved energy.

V. RESERVE MARGIN STUDY

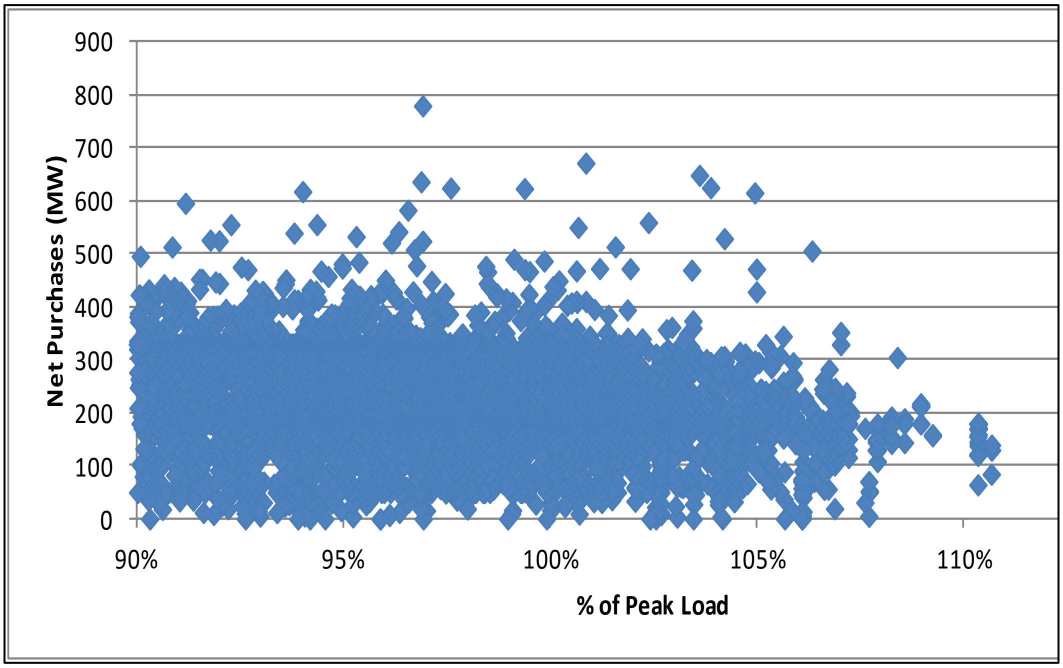
To determine the appropriate amount of generating capacity needed on the PNM system, the 2021 study year was simulated for a wide range of reserve margins. To reduce reserve margin levels, CT capacity was removed from the system and then incremental Frame CT resources were added to the system. Figure 15 shows the $LOLE_{CAP}$ from 10% to 24% reserve margin. As reserve margin increases, $LOLE_{CAP}$ decreases. The standard used in the electric industry is the 1 day in 10 year standard which translates to 1 firm load shed event every 10 years or 0.1 $LOLE_{CAP}$. To meet this standard, a 21% reserve margin is needed in the balancing area. Given the smaller size of PNM, Astrapé has recommended in previous testimony and reports that the minimum target reserve margin level should be set at 0.2 $LOLE_{CAP}$ which equates to a 17% reserve margin. Adopting this reserve margin would mean that the system should expect to have a firm load event due to capacity shortages two times every ten years. This 17% reserve margin is higher than the current approved reserve margin of 13% which would expect 4 firm load shed events every ten years.

Figure 15. Base Case Reserve Margin $LOLE_{CAP}$ Results



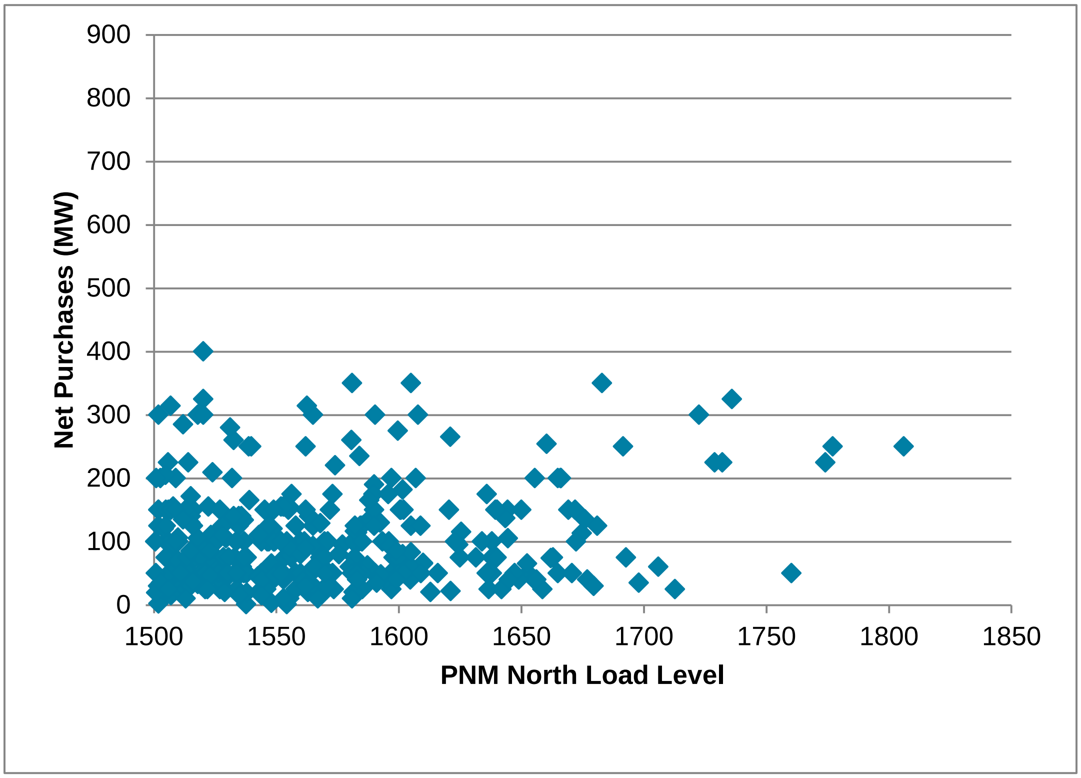
The Base Case Reserve Margin analysis assumes market assistance from neighbors based on the transmission inputs and load/resource balances discussed in the Input Sections of the report. Figure 16 shows the market assistance as a function of peak load during capacity shortage hours within the simulations. In the Base Case reserve margin study, the PNM balancing purchases several hundred MWs from neighboring regions. The simulations are stochastic, so in some hours there are zero MWs available, but in many hours when PNM has significant capacity offline due to forced outages there is substantial capacity in the marketplace.

Figure 16. Market Purchases as a Function of Peak Load



As current markets are changing within the WECC region, PNM believes there is risk in the simulations due to underlying market assistance assumptions. Figure 17 shows the actual purchases during peak load hours from 2013 - 2016. The actual values range from 0 - 400 MW. The majority of the points in Figure 16 align well with the actual values in Figure 17, however, a subset of the points from the simulations are higher than the 0 - 400 MW range.

Figure 17. Actual Purchases During Peak Load (2013-2016)



In order to understand how sensitive the results were to this assumption, the simulations were repeated capping the market assistance at 300 MW, 150 MW, and 0 MW which represents an island scenario. The 300 MW and 150 MW caps were developed from the actual purchases shown in Figure 17. Table 18 shows these results. In order to meet the 0.2 $LOLE_{CAP}$ requirement, a 22.5% reserve margin is needed for the 300 MW cap case and a 27.4% reserve margin is needed for the 150 MW cap scenario. In the island case, a 35% reserve margin is required. Given the large units on the PNM system and the total size of the system, the market interaction is a significant assumption and does impose risk on operators because while assistance from neighbors is expected in many hours there is no guarantee it will be available. In summary, Astrapé believes that the current 13% reserve margin is too low and PNM should at target at minimum a 17% reserve margin.

Table 18. Reserve Margin Sensitivities - $LOLE_{CAP}$

Reserve Margin	Base Case	300 MW Import Limit	150 MW Import Limit	ISLAND No Import Limit
9.1%	0.73	Did not simulate	Did not simulate	Did not simulate
10.7%	0.54	Did not simulate	Did not simulate	Did not simulate
12.4%	0.44	Did not simulate	Did not simulate	Did not simulate
14.1%	0.33	Did not simulate	Did not simulate	Did not simulate
15.7%	0.24	0.74	2.33	Did not simulate
17.4%	**0.19**	0.47	1.75	Did not simulate
19.1%	0.14	0.38	1.18	Did not simulate
20.7%	0.11	0.23	0.96	Did not simulate
22.4%	0.07	**0.21**	0.67	Did not simulate
24.1%	0.05	0.13	0.45	2.92
25.7%	0.03	0.08	0.29	1.85
27.4%	Did not simulate	0.04	**0.2**	1.43
29.0%	Did not simulate	0.03	0.12	0.87
30.7%	Did not simulate	Did not simulate	Did not simulate	0.61
32.4%	Did not simulate	Did not simulate	Did not simulate	0.39
34.0%	Did not simulate	Did not simulate	Did not simulate	**0.24**

To address a question that was asked in the public Advisory Session, Astrapé reviewed how the results were impacted if only the last ten years of weather were included in the modeling. This can be performed by attributing 0% probability to the first 26 years and giving 10% probability to the last 10 years. The results did not indicate a dramatic difference. At the 17.4% reserve margin level, the $LOLE_{CAP}$ is 0.176 events per year when only including the most recent 10 years of weather versus the 0.19 reported over all 36 weather years. This results in approximately a 1.5% reduction in reserve margin to meet the 0.2 $LOLE_{CAP}$ target.

VI. FLEXIBILITY METRICS

Using the 2021 current portfolio and the 2024 SJGS Retires portfolio, the operational capability of the system to meet net load ramps on a 5-minute basis was analyzed. Recall from the input sections that the regulation up requirement is 4% of load in all hours and that load is shed in the simulations to maintain this minimum level of operating reserves. SERVM also commits enough resources on the system to maintain a load following target in addition to the regulation up requirement which was varied in the analysis at 3%, 5%, and 7% of load. In addition, there was a 4% non-spinning requirement modeled in each of the simulations. With a higher load following target (online reserves), the system better manages net load ramps when wind or solar decreases unexpectedly. The 2021 and 2024 results are shown in Table 19. $LOLE_{FLEX}$ is reduced as the load following target increases, but renewable curtailment or overgen events increase. Also, PNM balance area costs increase as load following increases. This is due to units being operated further from maximum output and at higher heat rates along with purchases made in the market to ensure the online reserves. The results show that with the current expansion plan, the $LOLE_{FLEX}$ events can be managed by increasing the load following target to 7%. The corresponding renewable curtailment is approximately 1% of the renewable fleet. Note the renewable penetration levels shown in the table are for the balancing area. This is simply the renewable generation divided by the load.

While the renewable fleet is larger in 2024, the retirement of San Juan 1 and 4 and the addition of gas peaking units provides additional flexibility to the system as shown by a lower $LOLE_{FLEX}$ value with 7% load following. Also, even though there is a higher reserve margin in 2021 (18.8% in 2021 vs. 15.9% in 2024), the $LOLE_{CAP}$ is lower for 2024 due to the retirements of San Juan 1 and 4 which are modeled with a 17% EFOR.

Table 19. 2021/2024 Flexibility Metrics

	BA Renewable Penetration / PNM Renewable Gen	LF Target	Renewable Curtailment	Renewable Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	Events Per Year	M$
2021 Current Portfolio	17%/2,322	3%	0.83%	19,579	0.165	1.02	339.3
2021 Current Portfolio	17%/2,322	5%	0.97%	22,833	0.141	0.25	343.6
2021 Current Portfolio	17%/2,322	7%	1.11%	26,265	0.138	0.16	348.0

	BA Renewable Penetration / PNM Renewable Gen	LF	Renewable Curtailment	Renewable Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	Events Per Year	M$
2024 SJ Retires	19%/2,714	3%	0.86%	23,800	0.095	1.74	473.5
2024 SJ Retires	19%/2,714	5%	0.98%	26,952	0.075	0.38	478.8
2024 SJ Retires	19%/2,714	7%	1.11%	30,453	0.072	0.1	483.9

Table 20 shows the physical reliability metrics on a monthly basis for the 2024 study year with a 7% load following assumption. $LOLE_{CAP}$ events occur only during the summer while the flex events and renewable curtailment events can occur at any point during the year when net load moved unexpectedly on an intra- hour basis. From an EUE perspective, the cap events are much larger than the flex events. In fact, the $LOLE_{CAP}$ events reflect 275MWh per event while the $LOLE_{FLEX}$ events reflect 11.9 MWh per event. The $LOLE_{CAP}$ events last 2.85 hours per event while the $LOLE_{FLEX}$ events last less than an hour per event.

Table 20. 2024 SJGS Retires: Monthly Physical Reliability Metrics

2024 Month	$LOLE_{Cap}$ Events Per Year	$LOLE_{Flex}$ Events Per Year	EUE_{Cap} MWh	EUE_{Flex} MWh	Curtailment MWh
1	-	0.0006	0	0	3,874
2	-	0.0017	0	0	3,722
3	-	0.0067	0	0.02	2,958
4	-	0.0043	0	0.01	2,050
5	-	0.0036	0	0.01	2,881
6	0.0314	0.0231	13.27	0.33	1,367
7	0.0219	0.0321	3.83	0.54	910
8	0.0185	0.0192	2.66	0.29	879
9	-	0.001	0	0	1,412
10	-	0.0075	0	0.02	1,740
11	-	0.0028	0	0.01	4,058
12	-	0.0007	0	0	4,602
Total	0.0718	0.1031	19.75	1.23	30,453

Table 21 shows the results assuming San Juan 1 and 4 continues operation through 2024 and no Palo Verde lease extension. $LOLE_{CAP}$ increases compared to the San Juan Retires Case due to the high EFOR on the San Juan units. The removal of the PV lease benefits the system from a flexibility standpoint allowing renewable curtailment to decrease from the previous scenario. San Juan 1 and 4 also have reasonable turn down ratios[16] which helps maintain low renewable curtailment. Similar to the San Juan Retires Case, the results show that a 7% load following target is necessary to achieve reasonable reliability and manage the intra hour volatility of the load and renewable fleet. The costs decreased due to the lower fuel forecasts for San Juan compared to replacement gas capacity in the SJGS Retires Case. Recall that PNM Balance Area Costs do not include capital and fixed O&M.

[16] San Juan 1 was modeled with a minimum of 110 MW and San Juan 4 was modeled with a minimum of 115 MW.

Table 21. 2024 San Juan Continues

	BA Renewable Penetration/ PNM Renewable Gen	LF	Renewable Curtailment	Renewable Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	Events Per Year	M$
2024 SJ Continues	18%/2,592	3%	0.47%	12,273	0.16	1.42	431.1
2024 SJ Continues	18%/2,592	5%	0.58%	15,178	0.13	0.34	437.9
2024 SJ Continues	18%/2,592	7%	0.72%	18,909	0.13	0.16	445.4

Table 22 shows the results requested in the Advisory Session which retires Four Corners, San Juan 1 & 4, and excludes the PV lease from the portfolio. Due to the loss of inexpensive base load capacity, the balancing area costs increase dramatically. The flexibility metrics improve resulting in a 5% load following target required to maintain reliability. Renewable curtailment is also reduced under this scenario by approximately 0.5% versus the San Juan Retires Case.

Table 22. 2024 San Juan, Four Corners, and PV Lease Retire

	BA Renewable Penetration/ PNM Renewable Gen	LF	Renewable Curtailment	Renewable Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	Events Per Year	M$
2024 SJ, FC, PV Lease Retire	17%/2,393	3%	0.35%	8,537	0.04	0.68	503.8
2024 SJ, FC, PV Lease	17%/2,393	5%	0.50%	12,166	0.04	0.1	509.5

Retire							
2024 SJ, FC, PV Lease Retire	17%/2,393	7%	0.65%	15,881	0.03	0.03	515.4

VII. RENEWABLE PENETRATION STUDIES

To understand the impact of higher renewable penetration levels on the PNM system, 40%, 50%, and 80% renewable penetration scenarios were simulated for the 2024 study year. To develop these scenarios, a mix of solar and wind resources were added to the SJGS Retires Case without reducing any conventional capacity. This in turn, will only reduce $LOLE_{CAP}$, but the focus is on the operational aspects of the system for this analysis. For each of the renewable penetrations, a portfolio with more wind and one with more solar was developed using a 66.66%/33.33% ratio. Table 23 summarizes the portfolios that were simulated. Much higher load following is needed for the high penetration scenarios.

Table 23. Scenarios Simulated

Technology	LF Target
Base Case	3%, 5%, 7%
2024 SJGS Retires 40% BA RPS (66.7% Solar)	7%, 14%, 17%
2024 SJGS Retires 40% BA RPS (66.7% Wind)	7%, 14%, 17%
2024 SJGS Retires 50% BA RPS (66.7% Solar)	7%, 14%, 17%
2024 SJGS Retires 50% BA RPS (66.7% Wind)	7%, 14%, 17%
2024 SJGS Retires 80% BA RPS (66.7% Solar)	7%, 15%, 18%
2024 SJGS Retires 80% BA RPS (66.7% Wind)	7%, 15%, 18%

Table 24 shows the results if a load following target of 7% was maintained for each scenario. While not logical since operators would be forced to increase load following reserves as penetration levels increased, keeping the 7% shows how $LOLE_{FLEX}$ increases exponentially as more variable energy resources are added to the system. Also, curtailment of renewable generation rises steadily with the increase in renewables. In the 80% renewable scenarios, 30% - 40% of the renewable fleet is being curtailed. In the high solar cases, renewable curtailment is higher since more generation is concentrated across the day where as the high wind cases distribute the generation more evenly throughout the day. Balance area costs also increase dramatically because the PPA price is assumed for all renewable generation whether it is used to meet load or curtailed.

Table 24. Flexibility Metrics at 7% Load Following Target

	BA Renewable Penetration/ PNM Renewable Gen	LF Target	Curtailment	Curtailment	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	M$
2024 SJ Retires	19%/2,714	7%	1.11%	30,453	0.1	483.91
2024 SJ Retires 40% RPS (66.7% Solar)	39%/5,544	7%	12.08%	674,410	2.79	499.17
2024 SJ Retires 40% RPS (66.7% Wind)	38%/5,493	7%	8.15%	450,903	2.84	490.36
2024 SJ Retires 50% RPS (66.7% Solar)	49%/7,038	7%	21.63%	1,531,139	7.67	531.95
2024 SJ Retires 50% RPS (66.7% Wind)	48%/6,960	7%	14.16%	991,488	10.26	511.46
2024 SJ Retires 80% RPS (66.7% Solar)	80%/11,519	7%	41.06%	4,746,101	31.95	671.51
2024 SJ Retires 80% RPS (66.7% Wind)	79%/11,360	7%	31.45%	3,585,011	52.11	627.73

Figure 18 shows the $LOLE_{FLEX}$ with a 7% load following target graphically. Either load following targets need to be increased or additional flexible generation should be added to the system in order to reduce $LOLE_{FLEX}$ in the high renewable penetration scenarios.

Figure 18. LOLE$_{FLEX}$ with 7% Load Following as a Function of Renewable Penetration

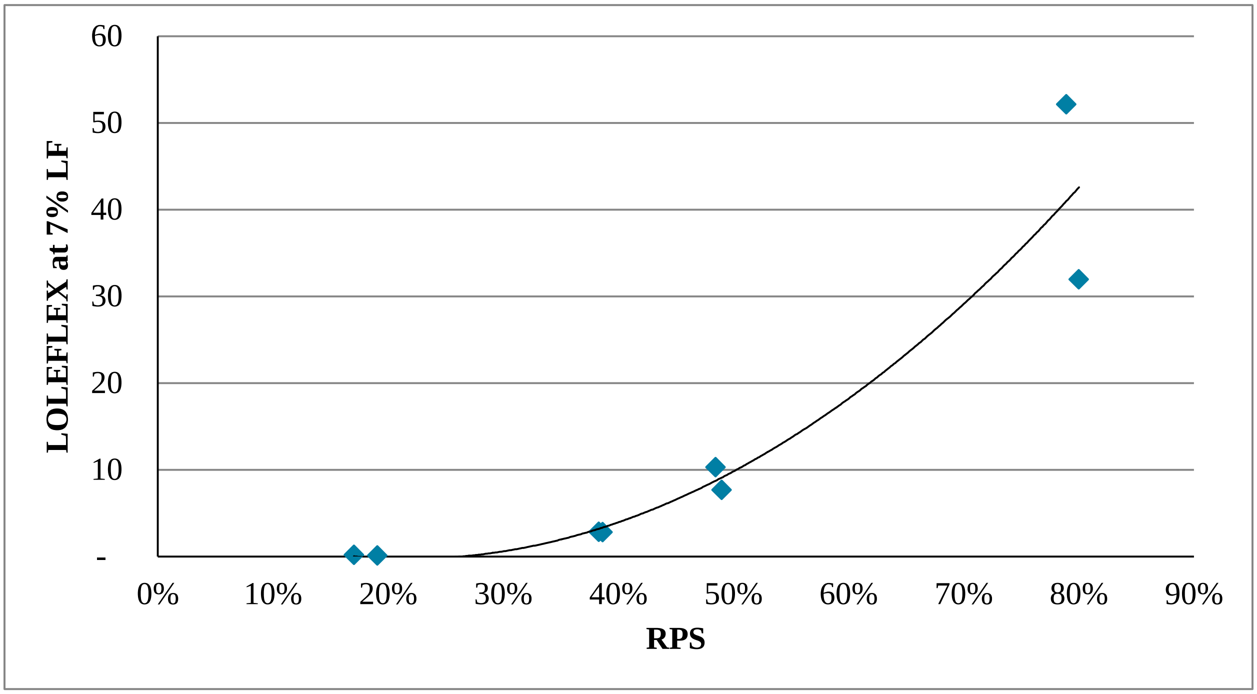


Table 25 shows the same scenarios with higher load following targets to achieve reasonable LOLE$_{FLEX}$. While the LOLE$_{FLEX}$ is reasonable for the 40% and 50% cases, additional load following or flexible resources are needed for the 80% penetration cases above the 18% load following assumption. The renewable curtailment and balance area costs are substantial compared to the Base Case. The renewable curtailment is likely the most significant problem with the higher penetration scenarios. As shown in the next section, to reduce the renewable curtailment in the high penetration cases, resources such as energy storage are required.

Table 25. Renewable Penetration Results Assuming Reasonable Load Following Targets

	BA Renewable Penetration/ PNM Renewable Gen	LF Target	Renewable Curtailment	Renewable Curtailment	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	% of Renewable	MWh	Events Per Year	M$
Base Case	19%/2,714	7%	1.11%	30,453	0.1	483.91
2024 SJ Retires 40% RPS (66.7% Solar)	39%/5,544	17%	17.58%	981,443	0.17	545.17
2024 SJ Retires 40% RPS (66.7% Wind)	38%/5,493	17%	13.41%	741,718	0.06	535.31
2024 SJ Retires 50% RPS (66.7% Solar)	49%/7,038	17%	26.10%	1,847,546	0.33	576.25
2024 SJ Retires 50% RPS (66.7% Wind)	48%/6,960	17%	19.90%	1,393,006	0.22	559.21
2024 SJ Retires 80% RPS (66.7% Solar)	80%/11,519	18%	45.50%	5,258,862	1.64	717.79
2024 SJ Retires 80% RPS (66.7% Wind)	79%/11,360	18%	37.20%	4,241,265	1.33	678.87

To achieve the 17% and 18% load following targets needed for the high penetration cases, the system must maintain 290 - 300 MW on average in online reserves as shown in Table 26. These values are incremental to the 4% regulation up requirement which is approximately 60 MW on average across the year.

Table 26. Load Following MW

Load Following % of Load	LF Average Across the Year MW
3%	100
5%	122
7%	139
14%	252

15%	262
17%	295
18%	302

Figure 19 shows renewable curtailment as a function of the balancing area's renewable penetration which was estimated from all the simulations. The black line represents the % of the total renewable fleet curtailed at each RPS level or the average curtailment at each RPS level. The red dotted line represents the marginal curtailment at each renewable penetration level. The chart shows that once the system is at 50% RPS, more than 60% of the next MWh will be curtailed.

Figure 19. Renewable Curtailment Rule of Thumb

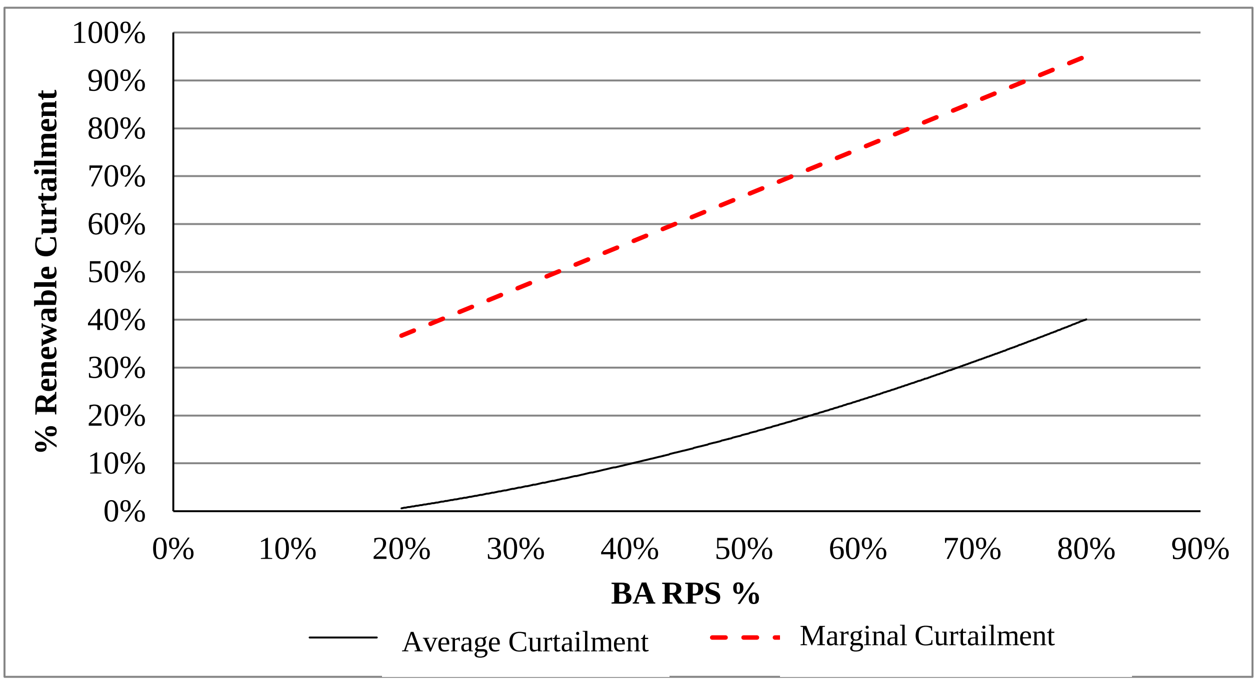
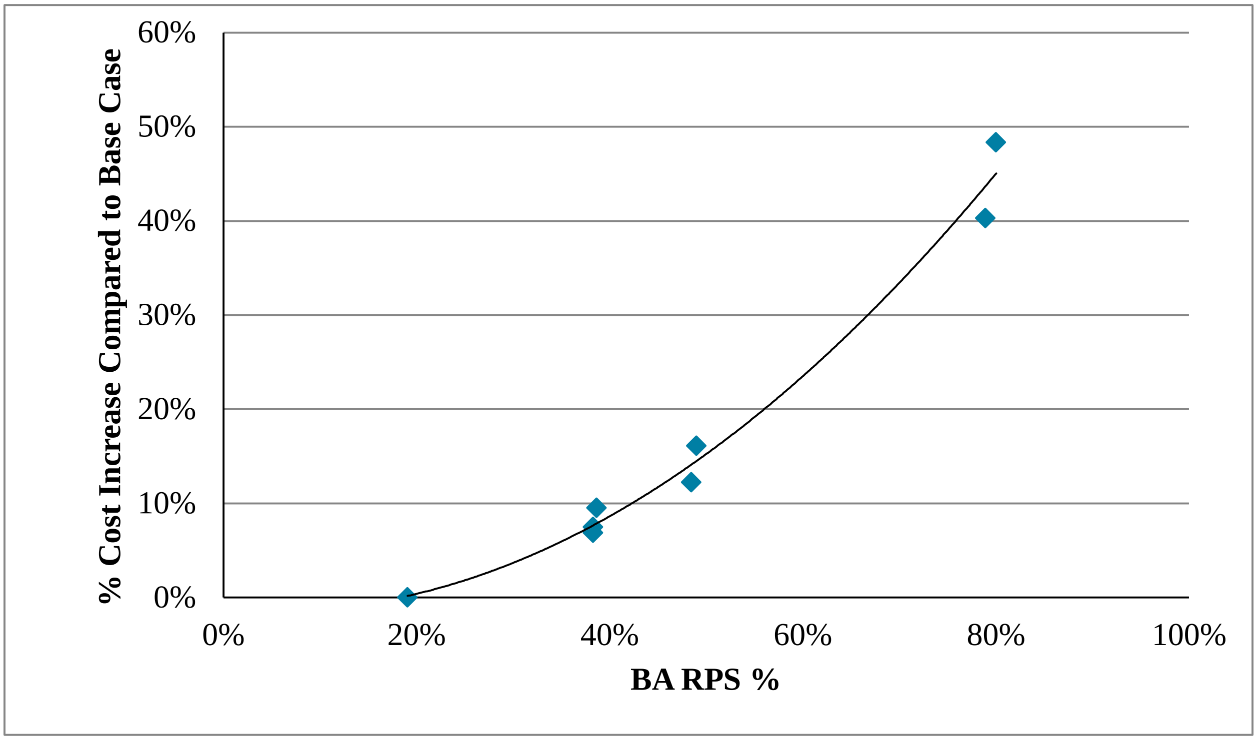


Figure 20 summarizes the balance area cost increase relative to the 2024 SJGS Retires Case. Again, the cost increases are driven primarily by two factors (1) renewable curtailment (2) higher load following targets.

Figure 20. Renewable Portfolio Cost Increases



VIII. ENERGY STORAGE AND FLEXIBLE GENERATION ANALYSIS

The final analysis included the addition of conventional CT capacity and energy storage to 2024 SJGS Retires Case and higher penetration scenarios.

First, the resources were added to the 2024 SJGS Retires Case. A 5% load following target was assumed to determine whether or not the addition of flexible generation would improve system reliability. The following resources were added to the system: (1) 2 LM 6000 at 40 MW each, (2) 100 MW battery with 2 hour storage, (3) 100 MW batter with 4 hour storage, and (4) 100 MW batter with 6 hour storage. The LM6000 resources were modeled after La Luz and Lordsburg while the battery resource characteristics were generic. The battery was assumed to be able to serve 100 MW of regulation up and down and had aa 90% charging efficiency. The battery was modeled with an EFOR of 4%. Table 27 shows the 2024 SJGS Retires Case results, Table 28 shows the 40% renewable penetration results and Table 29 shows the 50% renewable penetration results. In looking at the 2024 SJGS Retires Case results with a minimal amount of renewable curtailment, the energy storage does not provide much value. In fact, if we take the total balance area costs delta between the base case and each of the 2, 4, and 6 hour storage scenarios, the energy storage only provides between \$17/kW-yr to \$34/kW-yr in annual value[17]. The benefit would not support a new build energy storage project. The 2 LM6000 resources provide a total of \$37/kW-yr in annual value. Because the load following target isn't increased in any of these runs, the $LOLE_{FLEX}$ reduction is minimal. Also, since the CT resources have a start time of 10 minutes, the results show that the majority of the $LOLE_{FLEX}$ events are less than 10 minutes and can only be avoided by having more online reserves. While the storage provides online spin, SERVM is counting it towards the 5% load following requirement and therefore the $LOLE_{FLEX}$ is not impacted although it is serving as a cheaper online reserve option.

Table 27. 2024 SJ Retires Case: Add Flexible Generation and Energy Storage

	BA Renewable Penetration/ PNM Renewable Gen	LF Target	Curtailment	Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	%	MWh	Events Per Year	Events Per Year	M$
2024 SJ Retires	19%/2,714	5%	0.98%	26,952	0.0747	0.38	478.78
2024 SJ Retires and 2 LM6000 (80 MW)	19%/2,714	5%	0.92%	25,306	0.03	0.32	475.85
2024 SJ Retires and 100 MW 2 hour storage	19%/2,714	5%	0.92%	25,206	0.0863	0.38	477.06
2024 SJ Retires and 100 MW 4 hour storage	19%/2,714	5%	0.84%	23,019	0.0678	0.37	475.87
2024 SJ Retires and 100 MW 6 hour storage	19%/2,714	5%	0.85%	23,354	0.0788	0.31	475.39

[17] (\$478.78M - 477.06M)/100,000 kW = \$17/kW-yr

Table 28 shows the same analysis for the 40% penetration scenario. Recall that this portfolio is already reliable from an $LOLE_{CAP}$ standpoint since only incremental renewable resources were added to the 2024 SJGS Retires Case to achieve higher penetration levels. The 2 LM6000 resources provide $37/kW-yr in value but do not reduce renewable curtailment or $LOLE_{FLEX}$. The energy storage resource greatly reduces renewable curtailment and produces a value of $163/kW-yr to $195/kW-yr. The reason the energy storage resource provides such tremendous value is it is providing extremely cheap load following and reducing renewable curtailment.

Table 28. 2024 40% Renewable Penetration: Add Flexible Generation and Energy Storage

	BA Renewable Penetration/ PNM Renewable Gen	LF Target	Curtailment	Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	%	MWh	Events Per Year	Events Per Year	M$
2024 SJ Retires 40% RPS (66.7% Wind)	38%/5,493	14%	11.46%	634,370	0.04	0.13	520.07
2024 SJ Retires 40% RPS (66.7% Wind) and 2 LM6000 (80 MW)	38%/5,493	14%	11.55%	638,933	0.02	0.13	517.14
2024 SJ Retires 40% RPS (66.7% Wind) and 100 MW 2 hour storage	38%/5,493	14%	8.72%	482,265	0.01	0.13	503.79
2024 SJ Retires 40% RPS (66.7% Wind) and 100 MW 4 hour storage	38%/5,493	14%	8.18%	452,470	0	0.12	500.73
2024 SJ Retires 40% RPS (66.7% Wind) and 100 MW 6 hour storage	38%/5,493	14%	8.07%	446,422	0.01	0.1	500.6

Take Figure 21 for example which shows the renewable curtailment for a high penetration scenario. The red line represents the total renewable output plus must run nuclear resources online. The blue line represents load. In hours 11 through 17, a significant amount of renewable curtailment occurs. If an energy storage resource can shift this energy for use later in the day, substantial savings can be realized for the system. The results show that moving from 4 hour to 6 hour storage only provides marginally more savings and is likely not worth the additional capital costs.

Figure 21. Renewable Curtailment Daily Example

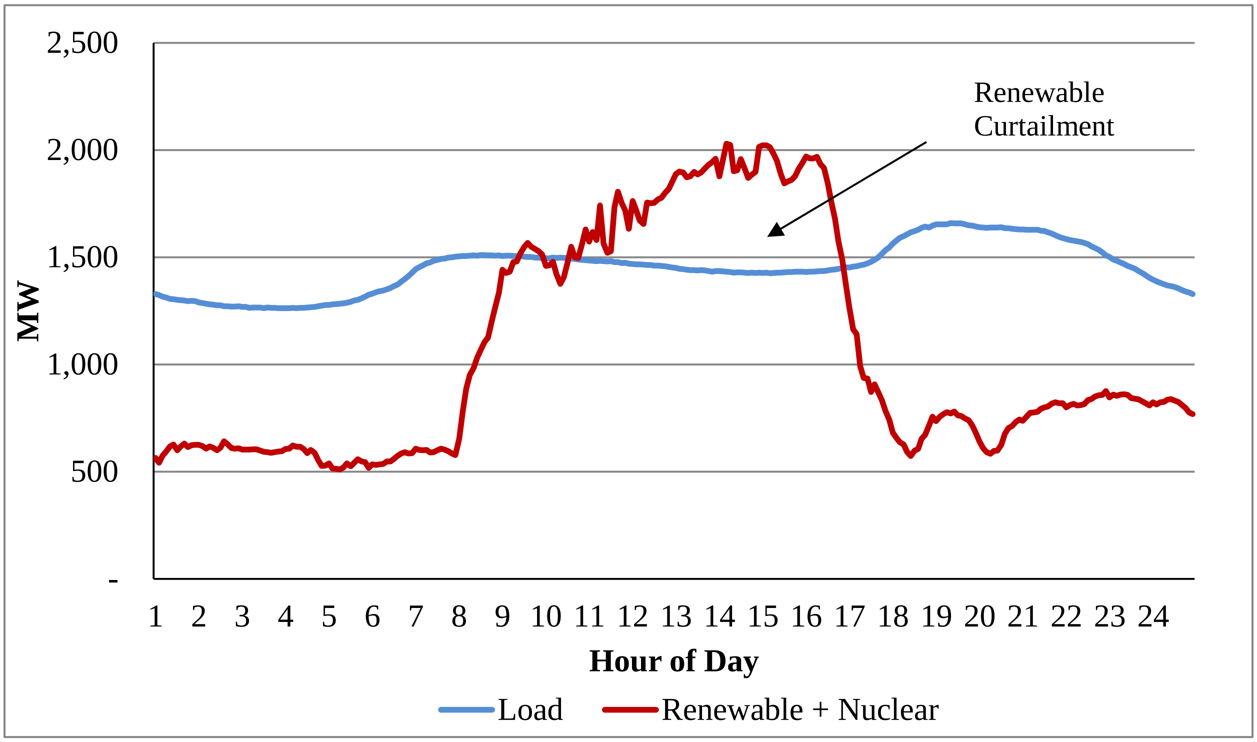


Table 29 shows the 50% results. Similar to the 40% renewable penetration results, the energy storage provides a value of $221/kW-yr to $255/kW-yr. Renewable Curtailment is reduced from 18% of the fleet down to 13% - 15% of the fleet. This analysis further shows the importance energy storage will play as renewable penetrations increase significantly.

Table 29. 2024 50% Renewable Penetration: Add Energy Storage

	BA Renewable Penetration/ PNM Renewable Gen	LF Target	Curtailment	Curtailment	$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load/GWh	% of Load	%	MWh	Events Per Year	Events Per Year	M$
2024 SJ Retires 50% RPS (66.7% Wind)	48%/6,960	14%	17.97%	1,257,800	0.03	0.43	543.08
2024 SJ Retires 50% RPS (66.7% Wind) and 100 MW 2 hour storage	48%/6,960	14%	14.52%	1,016,502	0.01	0.43	520.99
2024 SJ Retires 50% RPS (66.7% Wind) and 100 MW 4 hour storage	48%/6,960	14%	13.88%	971,548	0.01	0.39	517.84
2024 SJ Retires 50% RPS (66.7% Wind) and 100 MW 6 hour storage	48%/6,960	14%	13.73%	961,211	0	0.4	517.53

PNM: Powering New Mexico Since 1917

About PNM

Founded in 1917 as Albuquerque Gas and Electric Company, PNM is a subsidiary of PNM Resources, a utility holding company based in Albuquerque, NM, and the only New Mexico-headquartered company traded on the New York Stock Exchange (NYSE:PNM). PNM employs more than 1,500 New Mexicans.

Albuquerque Gas and Electric Company Headquarters on 5th and Central in 1938

Reliable, Affordable Electricity for Homes and Businesses

PNM provides electricity to more than 500,000 New Mexicans living in seven pueblos and more than 40 communities, including Albuquerque, Santa Fe, Rio Rancho, Belen, Alamogordo, Las Vegas, Ruidoso, Deming and Silver City.

- Consistently in top quartile performance nationally for reliability.
- Average residential bills in the top 25 percent for affordability in the region based on percent of annual household income.
- Industrial rates ranked in the top 25 percent for affordability for the region.

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Funded by PNM customers, employees and shareholders, this program provides financial assistance to customers who are experiencing financial challenges and meet certain income and account requirements. Qualified customers may receive payment towards a past-due PNM electric bill. Learn more at ***PNM.com/goodneighbor-fund.***

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Each year, PNM and the PNM Resources Foundation assist New Mexico communities with more than $3 million of support to nonprofit organizations. Since 1983, the Foundation has invested more than $14 million in local nonprofit organizations to build strong and vibrant communities. Through funding from PNM shareholders, employees, customers and our company, PNM also invests in the communities it serves in three key areas education, economic development and the environment. Learn more at ***PNM.com/community-investments.***

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