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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SAFE HARBOR STATEMENT

Statements made in this document that relate to future events or Public Service Company of New Mexico's (PNM's), expectations, projections, estimates, intentions, goals, targets, and strategies are made pursuant to the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based upon current expectations and estimates. Because actual results may differ materially from those expressed or implied by these forward-looking statements, PNM cautions readers not to place undue reliance on these statements. PNM's business is influenced by many factors, often beyond PNM's control, that can cause actual results to differ from those expressed or implied by the forward-looking statements. For a discussion of risk factors and other important factors affecting forward-looking statements, please see the PNM's Form 10-K and Form 10-Q filings with the Securities and Exchange Commission, the factors of which are specifically incorporated by reference herein.

PNM assumes no obligation to update this information, except to the extent the events or circumstances constitute material changes in the Integrated Resource Plan that are required to be reported to the New Mexico Public Regulation Commission pursuant to Rule 17.7.3.10 of the New Mexico Administrative Code.

TABLE OF CONTENTS

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EXECUTIVE SUMMARY

Background

Every three years, PNM is required to prepare an Integrated Resource Plan (IRP).[1] In this IRP, PNM has analyzed cost-effective power supply plans under two scenarios:

- San Juan Generating Station (SJGS) retires after the end of the current coal supply agreement, terminating on June 30, 2022
- SJGS continues to operate beyond 2022

The purpose of an IRP is to identify the most cost-effective resource mix that would meet the projected electricity demands of PNM's customers over the next 20 years, and to develop a four-year action plan that is consistent with that resource mix. PNM prepared this IRP for the period 2017 through 2036, examining all cost-effective resource options for its energy portfolio under a wide variety of possible futures. The plan benefitted from a robust Public Advisory Process. PNM hosted 17 meetings statewide over the past year and heard from hundreds of stakeholders. The four-year action plan describes a specific course of action that PNM expects to follow to implement the findings of the IRP. The steps in the action plan are designed to confirm the assumptions in this report and maintain flexibility to adjust the mix of new resources as the price and capabilities of renewable energy, natural gas, and energy storage technologies evolve.

Key Findings

With this plan, PNM would be coal-free in 2031.

The most significant finding of the IRP is that retiring PNM's 497MW share of SJGS in 2022 would provide long-term cost savings for PNM's customers. The retirement will provide the opportunity to move from the fixed costs and baseload operation associated with coal plants to resources that better match varying loads and are better equipped to work with renewable energy.

The results of the IRP illustrate that energy needs are changing, and replacing coal supply with renewable energy and more flexible generators will save money for customers in the long run. The analysis found that exiting PNM's 13% share in the Four Corners Power Plant (FCPP) after the coal supply agreement expires in 2031 would also save money for PNM's customers. This action would eliminate all coal-fired generation from PNM's resource portfolio.

Retiring SJGS would result in the loss of jobs in the Farmington area. These high wage positions will not be easily replaced. Consistent with what PNM did to address the impact of retiring SJGS Units 2 and 3 – supporting workforce retraining and local economic development

[1] In accordance with 17.7.3 New Mexico Administrative Code, Integrated Resource Plan for Electric Utilities.

programs – PNM will explore opportunities to address economic impacts with affected communities.

The assessment of coal plant retirements assumes full cost recovery of PNM's remaining investment in SJGS and Four Corners. This is consistent with core principles of the "regulatory compact," under which PNM is obligated to provide reliable and efficient service to all customers in a given area, work in their best interests and meet state and federal regulations. In return, PNM is entitled to recover the costs of providing service, including the opportunity to make a reasonable return on prudent investments.

New Supply-Side Resources

PNM recognizes that renewable energy, natural gas, and energy storage technologies are rapidly evolving. The best mix of new resources currently includes solar energy and flexible natural gas-fired peaking capacity. The mix may also include energy storage, depending on the economics of the proposals PNM receives through a solicitation that the company will conduct as described in the four-year action plan. Although wind energy is also a possibility, the existing transmission system from Eastern New Mexico, where the best potential for wind supplies exists, is currently fully subscribed. This limits the ability for new wind resources to meet energy supply needs until new transmission capability is built.

Over the four-year action plan period, PNM will validate the assumptions in this report by issuing a request for proposals and may rebalance the mix of SJGS replacement resources as a result of bids received through that process.

Continuing Supply-Side Resources

Through 2022, PNM's existing supply-side resources, except for SJGS, will remain a part of the cost-effective resource portfolio. These resources provide energy and capacity from renewable sources (wind, solar, and geothermal) as well as nuclear, coal, and natural gas powered resources.

PNM owns 288 MW of Palo Verde Nuclear Generating Station (PVNGS) and leases another 114 MW, with leases of 104 MW expiring in 2023 and 10 MW expiring in 2024. Retention of this leased capacity beyond 2025 avoids the need to replace it with carbon emitting generation, preserving the CO_2 emission reductions that result from the coal plant retirements. Moreover, retention of the leased capacity preserves carbon-free baseload capacity that is needed, particularly after the retirement of all of PNM's coal-fired baseload resources. Maintaining PVNGS capacity also minimizes freshwater use and serves as a balance against potential increases in natural gas prices.

Access to Power Markets

PNM utilizes energy purchases and sales from the wholesale market to enhance reliability and reduce costs to customers. Power markets are changing rapidly. PNM's plan includes an assessment of how best to maintain real-time opportunities to purchase and sell energy by studying the costs and benefits of joining the California Energy Imbalance Market (EIM).

Assess and Update Existing Systems

As part of the IRP analysis, PNM studied its power transmission system to identify locations for new resources that would not require construction of additional transmission. Retiring SJGS and Four Corners will require replacement resources in the Four Corners region. Some locations are preferable to others in terms of the cost to interconnect new resources and the need to maintain adequate energy supply throughout PNM's Balancing Area.

The four-year action plan includes an assessment of PNM's oldest power plant: the three-unit Reeves Generating Station. Maintaining energy supply at Reeves is a critical element of PNM's system reliability for Albuquerque. PNM will consider possible technology improvements to phase out the older generators and replace them with new, more flexible supplies or energy storage.

The Most Cost-Effective Portfolio

The Most Cost-Effective Portfolio (MCEP) is summarized in Figure 1. PNM recommends this plan because it best meets the objectives to "identify the most cost-effective portfolio of resources to supply the energy needs of customers. For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts." This plan cost-effectively maintains a reasonable reliability expectation, while achieving the lowest freshwater use and carbon emissions and meeting regulatory requirements.

Figure 1. MCEP Summary

BEFORE 2022	• Meet RPS and EUEA targets • Execute four-year action plan
IN 2022	• Retire PNM's SJGS capacity • Retain PVNGS leases • Replace SJGS with renewable resources, natural gas peaking capacity, and potentially energy storage
AFTER 2022	• Build new transmission to transmit wind energy from Eastern New Mexico • Meet load growth with additional renewable energy, gas peaking, or energy storage • Replace expiring Valencia purchase in 2028 • Pursue replacement of Four Corners coal plant in 2031

Four-Year Action Plan

The Recommendations Section of this IRP further details the four-year action plan. In summary, PNM will do the following over the plan period:

- Continue to develop and implement energy efficiency and demand management programs
- Add renewable energy resources to maintain compliance with the Renewable Portfolio Standard (RPS)
- Explore options to maintain system supply and reliability
  - Assess the costs and benefits of joining the California Energy Imbalance Market
  - Participate in regional transmission planning groups
  - Complete an economic assessment of the Reeves Generating Station to develop a plan for Reeves that coordinates with the need for replacement resources, assuming PNM retires SJGS in 2022
- File for SJGS abandonment with the New Mexico Public Regulation Commission
  - Issue a request for proposals to for energy storage, renewable energy and flexible natural gas resources to confirm the assumptions and analysis results in this report and to further refine the mix of replacement resources assuming SJGS retires in 2022
  - Make a filing with the NMPRC to determine the extent to which SJGS should continue serving PNM's retail customer's needs after June 30, 2022. This filing will occur after July 1, 2018, but no later than December 31, 2018
  - Define SJGS replacement resource siting requirements by analyzing transmission system needs
- Secure the PVNGS leased capacity
- Identify the best opportunities to increase transmission capacity to Eastern New Mexico to allow for future expansion of wind energy resources
- Conduct the 2020-2040 Integrated Resource Plan

INTRODUCTION

TIMELINE

1882

A.A. Grant established the Albuquerque Gas Company and built a gas plant – manufacturing gas made from nitrogen, carbon monoxide, hydrogen, and coal or coke--for distribution to local businesses and residences. Perfecto Armijo established the Albuquerque Electric Light Company and immediately sold the company to A.A. Grant and Dennis Dennison. The company built a new power plant with a 250-kilowatt generator.

1917

The two Albuquerque companies: Albuquerque Electric Power Company and Albuquerque Gas, Electric Light and Power Company merge into a new organization, the Albuquerque Gas & Electric Company.

1922

New generation is needed and the Albuquerque Sawmill Power Plant adds Unit 4 capable of generating 2,500 KW.

1929

The first inter-city electric transmission line in New Mexico is completed and connects Albuquerque to Santa Fe ending the dependence of each city on its own town power plant. The construction crews worked in rough terrain and long hot summer days with only tents for shelter.

1939-1945

World War II stimulated the need to unite the geographically widespread distribution and transmission systems in New Mexico. Government defense and research installations like Kirtland Air Force Base, Sandia Laboratory, Los Alamos National Laboratory, and White Sands Missile Range led to increased power demands.

1946

In 1946, the Albuquerque Gas and Electric Company changed its corporate name to the Public Service Company of New Mexico (PNM) and acquired the properties of New Mexico Power Company, Deming Ice and Electric Company, and Las Vegas Light and Power Company.

1964

WEST, an organization serving nine western states forms and plans to jointly build a power plant, the coal-fired Four Corners Plant in northwestern New Mexico. PNM also announced plans with Tucson Gas and Electric Company to build San Juan Generating Station, which would have state-of-the-art pollution controls.

1972

PNM lists on the New York Stock Exchange and the San Juan Generating Station begins operation.

1985

The firm acquires the Gas Company of New Mexico from Southern Union.

1985

Palo Verde Nuclear Generating Station begins providing nuclear power to PNM and other utility customers across the Southwest.

2003

PNM begins purchasing power generated by the New Mexico Wind Energy Center near Ft. Sumner, establishing PNM as a leader among energy companies adopting wind into their portfolios.

2005

PNM buys TNP Enterprises, a privately owned holding company for Texas-New Mexico Power Company (TNMP) and First Choice Power (First Choice). The New Mexico Efficient Use of Energy Act helps PNM create energy efficiency programs and is the basis for the IRP rule.

2008

PNM sells gas operations to New Mexico Gas Company. Pat Vincent-Collawn named PNM Resources president and chief operating officer.

2011

Leading in renewable energy science, the 500 kW PNM Prosperity Solar Energy Storage Project comes online south of Albuquerque. The Las Vegas solar facility begins operation, making it the first of 15 new solar farms to be constructed across New Mexico.

2016

Agreement reached for PNM to provide electricity through renewable resources for a new Facebook Data Center in Los Lunas. Energy will be provided through three new solar farms currently under construction.

2017

PNM celebrates 100 years of powering the energy needs of New Mexico and looks ahead to our next century of service.

FUTURE

INTRODUCTION

This Integrated Resource Plan (IRP) identifies the types of resources that PNM will need in the future to continue to provide reliable, cost-effective electric service while also reducing environmental impacts related to the generation and transmission of electricity. PNM prepared the plan in accordance with several rules, regulations, and guiding principles. The recommendations and action plan items were based on rigorous analysis of an extensive array of commercially available resource options that consider a wide variety of ideas of how the future may unfold.

PNM's analysis began with an assessment of the electric service its customers will need in the future to provide energy for their jobs and daily life. This assessment incorporated three guiding principles: maintain reliability, provide service at reasonable costs, and reduce the impact to the environment below current levels. Reliability is the result of delivering electricity to customers when needed with a minimal probability of interruption or disturbance.

The electric grid is one of the largest and most complicated machines in the world. Building and maintaining it has always been a capital intensive endeavor. Recent technological advances, and expected future advances, are creating opportunities to add or replace existing resources at reasonable costs while maintaining reliability and reducing air emissions and water use. This report includes the information considered, the analysis performed, and the recommendations that follow from the yearlong IRP process.

IRP Process

PNM has prepared this IRP to meet all requirements of Part 17.7.3 of the New Mexico Administrative Code (NMAC), Integrated Resource Plan for Electric Utilities (IRP Rule). This is PNM's fourth IRP filing under the IRP Rule, which was issued by the New Mexico Public Regulation Commission (NMPRC) on March 1, 2007 and amended on November 27, 2012.

The IRP Rule requires that New Mexico electric public utilities file an IRP that contains the following (17.7.3.9(B) NMAC):

- A description of existing electric supply-side and demand-side resources
- A current load forecast
- A load and resources table
- Identification of resource options
- A description of resource and fuel diversity
- Identification of critical facilities susceptible to supply source or other failures
- A determination of the most cost-effective resource portfolio and alternative portfolios
- A description of the public advisory process
- An action plan
- Other information that the utility finds may aid the NMPRC in reviewing the utility's planning processes

The rule requires New Mexico electric public utilities to file an IRP every three years. In addition to complying with the requirements of the IRP rule, in a Stipulation approved in NMPRC Case No. 13-00390-UT, PNM agreed to present most cost-effective portfolios under two scenarios in this report: (1) where San Juan Generating Station (SJGS) completely shuts down after the end of the current coal supply agreement, which terminates on June 30, 2022, and (2) where SJGS continues to operate beyond 2022. In addition, PNM committed in the Stipulation to the following:

- After July 1, 2018, but no later than December 31, 2018, PNM shall make a filing with the NMPRC, and serve all parties to this case, to determine the extent to which SJGS should continue serving PNM's retail customers' needs after June 30, 2022.
- PNM shall provide participants in the IRP process and parties in the 2018 review reasonable access to inputs, assumptions, and constraints regarding Strategist runs, and will perform a reasonable number of Strategist runs using practical assumptions as requested by stakeholders engaged in the IRP process (Stipulation Paragraph No. 19).[2]
- PNM will issue a Request for Proposal (RFP) as soon as practicable after the filing of the 2017 IRP. The RFP will request proposals for resources identified in the IRP as the most cost-effective portfolio (MCEP) using the assumption that SJGS does not continue to operate past 2022 (non-SJGS alternative).

The goal of the IRP process is to identify the most cost-effective resource portfolio that meets the projected electric demands of PNM's electric retail customers over the next 20 years and develop a four-year action plan that is consistent with the MCEP.

The IRP planning process, on a macro level, identifies the mix of resources that, together, will reliably meet system operational requirements, including delivery to customers that is consistent with applicable regulatory requirements. For planning purposes, PNM used known and reasonably expected variables to develop assumptions. These include assumptions about technology availability and price, current regulations, anticipated future regulations, and consumer usage patterns. This planning process will help to create a portfolio that allows PNM to respond to projected future events and ensure adequate resources are available to meet demand and maintain service reliability. The IRP is updated every three years or sooner, if material changes in assumptions would lead to a different course of action.

Approach

PNM designed a multidimensional process for its IRP analyses to determine the most cost-effective resource portfolio for the 20-year period from 2017 through 2036. The process included reviewing existing resources, forecasting future energy needs, examining future resource options, and designing scenarios, sensitivity analyses, and probabilities of risks and uncertainties to evaluate various resource portfolios. The goal was to meet customers' electric service needs in the most cost-effective manner while also meeting all requirements for system reliability as well as security, safety, and environmental regulations.

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[2] The Strategist software is described in the Analytical Tools section.

PNM invited the public to participate in the planning process. The goals for public participation were twofold. First, to provide information to interested stakeholders regarding the resource options available and, second, to allow for feedback regarding the assumptions and calculations and affirmation of the breadth and focus of the process as well as the public's prioritization in resource planning. PNM considered these factors and the Public Advisory group's input when analyzing different customer load and resource options under different future assumptions.

PNM considered the input from the IRP Public Advisory Process participants in evaluating the plan. This input included cost calculations and projections of future costs, current and potential environmental policy (its impacts and likelihood of becoming law), and system reliability regulations and how they might evolve as the electric grid changes.

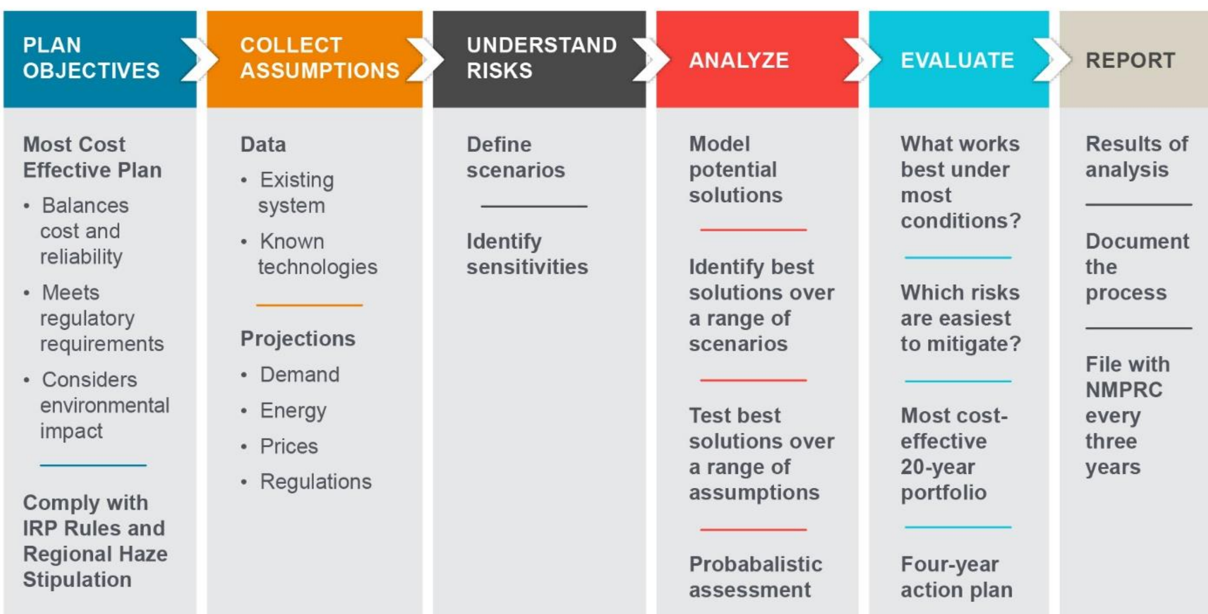
Determining the Most Cost-Effective Resource Portfolio

PNM identified the MCEP by considering a variety of factors including regulatory and environmental requirements, cost, environmental impact, and system reliability. Each portfolio was evaluated for potential financial risks and non-financial risks (such as reliability) and stakeholder impacts. The four-year action plan for the period from 2017 through 2021 outlines the near-term steps to implement the most cost-effective resource portfolio and ensure PNM is prepared for future transmission and emerging technology opportunities.

IRP Planning Process

PNM follows a structured six stage process for determining the MCEP, which is shown in Figure 2 and detailed in this section.

Figure 2. Most Cost-Effective Portfolio Process



Plan Objectives

The planning process begins with defining the objectives that the resulting plan must meet. The IRP rules and other regulatory requirements set these objectives. These objectives are described in detail in the next section of this report.

Collect Assumptions

Developing an IRP requires multiple assumptions. PNM collects data for use as inputs to the modeling. Table 1 provides a list of the data requirements.

Table 1. IRP Required Data

Data Types	Specifics
Load Forecast	Existing customer counts and load by rate class, historical and projected population growth, assumptions around growth in use per customer or customer class, large customer changes, wholesale contracts
Existing Generation	Additional capital improvement costs, operation and maintenance (O&M) costs, min/max capacity, heat rate, forced outage rate, maintenance schedules, production curves, fuel type, fuel price and contract prices
Historical and Future Energy Efficiency Savings	Energy and demand savings
Demand Response	Available capacity, limits on use, contract costs and terms.
New Generation	Capital costs, O&M costs, min/max capacity, heat rate, forced outage rate, daily availability, maintenance schedules, production curves, fuel type, fuel price, interconnection costs, siting considerations, water needs, transmission costs, and revenue requirements
Fuel Price Forecasts	Price forecasts for natural gas, fuel oil, coal, and nuclear fuel ranges
Regulations	Existing regulations and constraints, potential future regulations

Understand Risks

Given the inherent uncertainty of forecasts and possible future resource options, the next step of the IRP process is to understand the risks they represent to supplying power to customers in reliable, cost-effective, and environmentally acceptable ways. Using scenario and sensitivity analyses, the IRP process examines multiple versions of the future. PNM starts with the two overriding scenarios that look at whether SJGS continues to operate post 2022. Within those two scenarios, the alternate futures that vary load growth, fuel prices, and possible emission costs are considered. Each individual scenario is a different picture of the future that, taken all together, explores the capability of different resources to provide reliable energy services under combinations of load growth, fuel prices, and emission costs.

Sensitivity analysis is used to test assumptions within a scenario. For example, solar installation costs have been declining yet tax credits that affect installation costs are set to expire, so the future price of solar is uncertain. Testing a range of solar installation prices within a scenario will show if the MCEP is dependent upon future prices for solar.

Analyze

Using economic probabilistic dispatch modeling software, PNM can determine top ranked resource portfolios for each of these scenarios for the future of SJGS. These scenarios are then analyzed and evaluated under a variety of future conditions to understand the impacts over the study period. The future is unlikely to look exactly like any one of the conditions analyzed; therefore, it is important to know how well each portfolio performs under varying assumptions of the future.

Evaluate

Through the IRP analysis processes, with the goal of identifying the building blocks of the most cost effective portfolio, it is possible to learn the following:

- Which elements of these portfolios work best under most conditions, that is, have the flexibility to mitigate risks if actual conditions significantly vary from projections
- Which portfolios have the lowest net present value of costs over time, including capital and operating costs, and how they rank compared to other portfolios
- The environmental impacts of those portfolios in terms of air quality and water usage

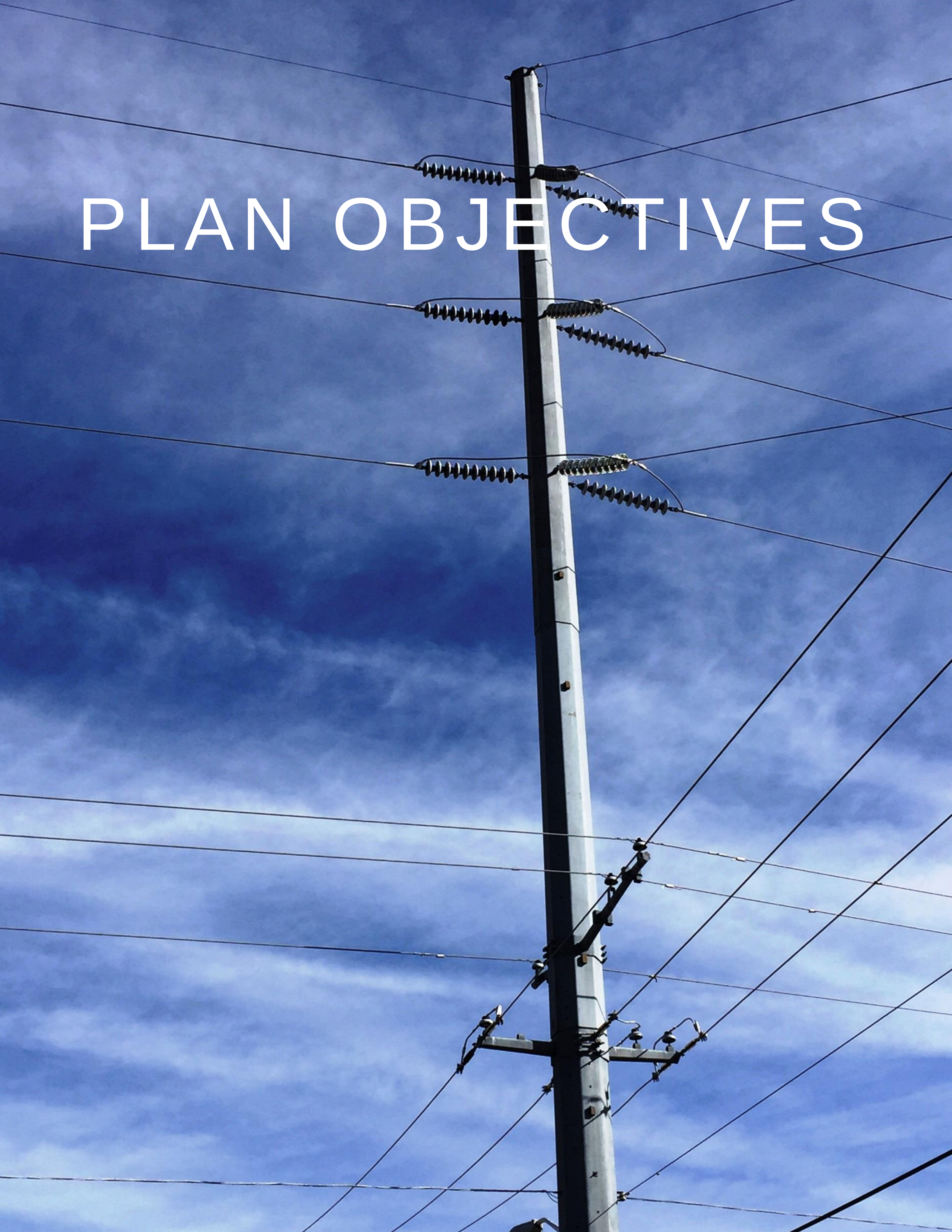
Throughout the IRP process, public participation is important to provide input for the assumptions used in the scenario analysis.

This IRP presents a four-year action plan that captures and describes the actions PNM must take to create the MCEP and to take advantage of potential future opportunities identified in the MCEP creation process.

Report

The IRP process requires identifying one resource portfolio, defined as the "most cost-effective portfolio," and the development of a four-year action plan to begin implementing the portfolio. In the case of this IRP, PNM identifies an MCEP with an action plan based on the SJGS scenarios and alternate portfolios that show how the MCEP is affected by changing elements like PVNGS or renewable energy supplies. After filing the IRP, PNM will issue an RFP to solicit proposals for new resources to test the resource assumptions and MCEP analysis provided in this report.

PLAN OBJECTIVES



PLAN OBJECTIVES

The New Mexico IRP Rule states that the objective of the process is to “identify the most cost-effective portfolio of resources to supply the energy needs of customers. For resources whose costs and service quality are equivalent, the utility should prefer resources that minimize environmental impacts.” To determine the MCEP, PNM analyzed a wide variety of resource combinations under numerous assumptions of the future. PNM compared plans using the following metrics:

- **Net present value of revenue requirements:** the revenue requirements over the 20-year period for each resource plan under each set of future assumptions
- **Reliability metrics**: operating reserves, contingency reserves, and predicted loss of load events
- **Environmental impacts:** emission levels and water usage

The MCEP meets the following metrics for service quality:

- Sufficient reserves across the planning period
- Availability of operating reserves in every hour of every year
- Predicted Loss of Load Hours measurements that meet national and regional grid requirements

Additionally, PNM ensured that every MCEP meets these other regulatory requirements:

- Energy efficiency spending of 3% of revenue requirements
- Minimum renewable portfolio standards of 15% of retail energy sales met through renewable energy resources through 2019, and 20% from 2020 thereafter
- Minimizes environmental impacts relative to other plans with equivalent costs and service quality

The top ranked portfolios for each of the SJGS scenarios are resource plans that performed most favorably against the criteria shown in Figure 3, under the wide variety of futures analyzed through the planning process.

Figure 3. Plan Objective Criteria

COST	• Net Present Value of Revenue Requirements
RELIABILITY	• Peak Day Reserves • Hourly Operating Reserves • LOLH and LOLE
ENVIRONMENTAL IMPACTS	• CO2 Emissions • Water Usage • Other Emissions
REGULATORY REQUIREMENTS	• Energy Efficiency Spending • Renewable Portfolio Standards • Regional Haze Stipulation Requirements

IRP Rule Requirements

These objectives are based on the requirements of the IRP Rule. This report documents how the process of preparing this IRP meets all of the requirements of the IRP rule. Appendix G contains a tabulation of the individual rule requirements and notes the specific sections of this report that demonstrate how the process satisfies the requirement.

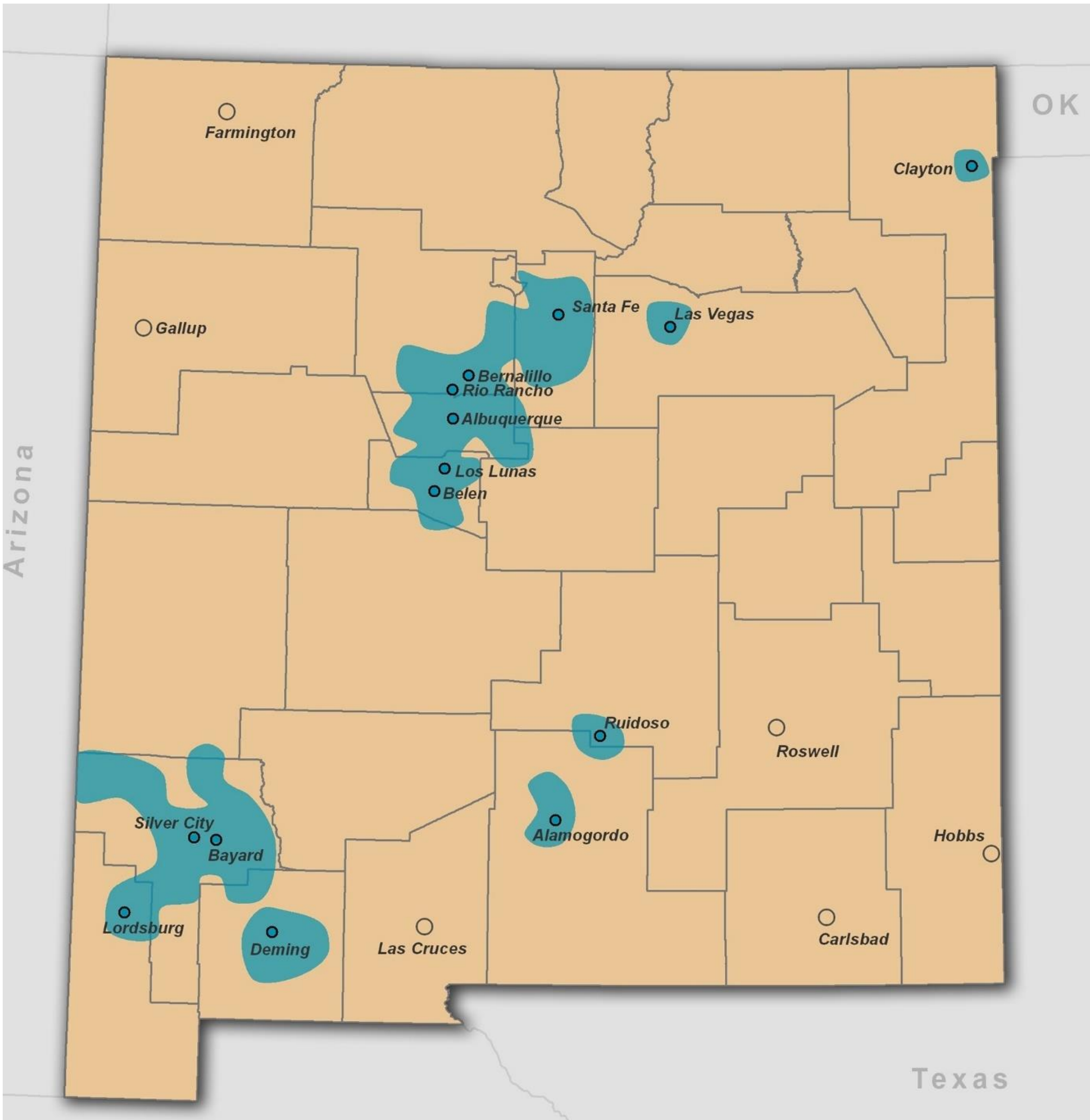
CUSTOMERS

CUSTOMERS

Service Territory

PNM has short and long term needs for resources that will provide capacity and energy to its customers, serving about 510,000 electricity customers statewide. As shown in Figure 4, PNM's electric service territory covers geographically diverse areas. Electric demand and energy usage varies based upon geography, customer mix, and climate. Recognition of these differences is important in preparing load forecasts.

Figure 4. PNM's Electric Service Territory Map



PNM is an integrated electric utility that provides generation, transmission, and distribution service. PNM's retail service territory covers a large area of north central New Mexico - most of the area around the Rio Grande valley from Belen to Santa Fe, including the cities of Albuquerque and Rio Rancho. Other communities served include Lordsburg, Silver City, Deming, Alamogordo, Ruidoso, Tularosa, Clayton, and Las Vegas. PNM also serves several New Mexico Pueblo nations and numerous unincorporated areas.

Over the 20-year planning period, PNM faces growing peak demand. The retail demand and energy forecast is developed by considering growth in customers, changing customer use, the economic trends in the region, changes in customer mixes, as well as projected energy efficiency and customer additions of solar and other distributed resources. PNM develops the resource plan to serve future system loads, maintain system reserve margins, and meet regulations for energy efficiency and renewable energy, as well as other applicable requirements. This section of the IRP reviews historical loads and discusses the methodology used to create the current load forecast and the load forecast scenarios used for the IRP analysis. Appendix A includes additional data on the load forecast.

Transmission System Customers

In addition to its retail customers, PNM provides generator interconnection and transmission delivery services pursuant to the terms and conditions of its Federal Energy Regulatory Commission (FERC) approved Open Access Transmission Tariff (OATT). PNM provides significant amounts of transmission service (40% to 45% of total transmission utilization) to other entities (network integration and point-to-point transmission service), as discussed below. Pursuant to its OATT, PNM must plan its transmission system to meet the needs of both its retail jurisdictional customers and its transmission customers.

Network Integration Transmission Service Customers

Network customers include these entities: Tri-State Generation and Transmission Association (Tri-State), Los Alamos County, Navajo Tribal Utility Authority, Western Area Power Administration (WAPA) for Kirtland Air Force Base, Sandia National Laboratory, City of Gallup, Jicarilla Apache Nation, and PNM Wholesale Power Marketing (for PNM retail).

Point-to-Point Transmission Service Customers

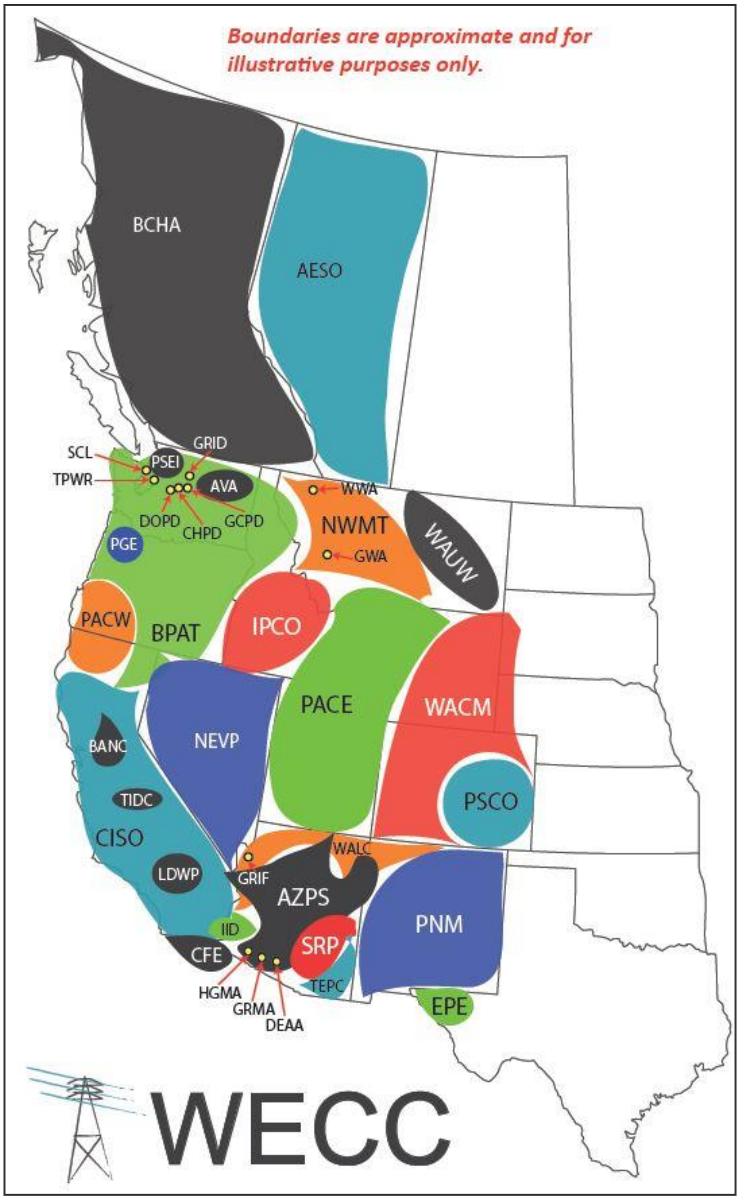
Point-to-point customers include El Paso Electric Company, High Lonesome Mesa, Aragonne Mesa, NextEra, WAPA, and Broadview Wind.

Power Balancing and Transmission Services

PNM ensures electric reliability in real time through balancing operations and transmission operations. Balancing operations ensures that the supply of power and the demand for power within the PNM system remains in balance to maintain 60 Hz power frequency. PNM has this responsibility within its operating footprint and shares grid balancing responsibility with approximately 38 other operating entities in the Western Electricity Coordinating Council (WECC), as shown in Figure 5. Transmission operators monitor power flow and voltage levels on transmission elements (switching stations, lines, and transformers) and, if necessary to ensure reliability, adjust the dispatch of generation, switching of shunt devices, adjusting transformer tap settings and switching transmission elements. Adjustments have included these examples:

- Controlling the voltage profile on the transmission system
- Restoring a facility in response to forced outages because of events like weather or animal contact
- Managing planned outages for maintenance and construction activity

Figure 5. WECC Grid Map of Balancing Area Boundaries



PNM maintains continuous operations (24 hours a day, seven days a week) to ensure reliability for its customers and prevent adverse effects on neighboring systems. PNM maintains reliability and alleviates problems by redispatching generators, switching facilities, adjusting interchange, curtailing scheduled energy deliveries, and if conditions require shedding load (as a last resort). National and regional entities monitor and regulate utilities' real-time operations both for national security reasons and to ensure that each grid participant meets its obligations for maintaining reliability and efficient operation of the electric grid. These include:

- Balancing performance
- Mitigating generation and transmission disturbances
- Training system operators
- Developing procedures and requiring adherence to those procedures
- Providing emergency plans

PNM operates under two regional reliability coordination centers, one located in Loveland, Colorado, and the other in Vancouver, Washington. The regional grid regulatory entities have authority delegated from the FERC.

Load Forecast

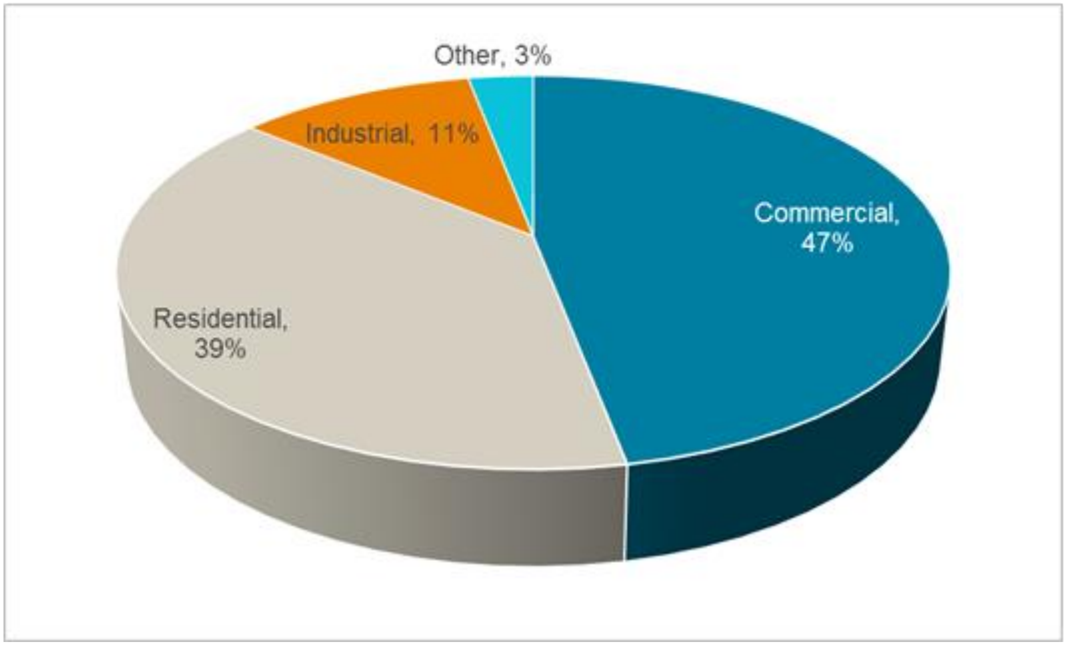
The load forecast is critical to the assessment of needed resources to meet future load growth as it provides the assumptions for peak demand and retail energy sales. The load forecast impacts the type and timing of resource additions or retirements. The load forecast is also a critical element of distribution and transmission system planning. Key inputs considered in the development of the load forecast include weather, economic activity, employment and population growth and energy consumption patterns of end users. Each of these variables is subject to extreme variations from the base projections, making it important to test resource plans against a range of potential forecasts. Table 2 is a breakdown of PNM's 2016 sales by customer class.

Table 2. 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**

In 2016, residential sales accounted for 39% of total retail sales, commercial sales accounted for 47%, and industrial sales accounted for 11% of total retail sales. The remaining two FERC classes (other public authorities and street lighting) represented only about 3% of retail sales, as shown in Figure 6.

Figure 6. Total Retail Sales by FERC Classes (2016)



For this IRP, PNM developed three load forecast scenarios—low, mid, and high—based on the most current assumptions as of July, 2016. The methodology described below and in Appendix A was used to develop the mid-forecast. The low- and high-load forecasts are intended to incorporate various aspects of forecast uncertainty, such as weather, the level of customer growth, economic activity, the pace of efficiency gains due to different energy efficiency costs and budget assumptions, and the variation in likely numbers of customers adopting distributed generation compared to the mid forecast. PNM developed the load forecast after the summer peak of 2016 to ensure the forecast considers system peak demand for the most current year. Figure 7 and

Figure 8 show the range of energy and demand forecasts considered in this IRP.

Figure 7. Comparison of PNM's Energy Forecast Sensitivities (GWh)

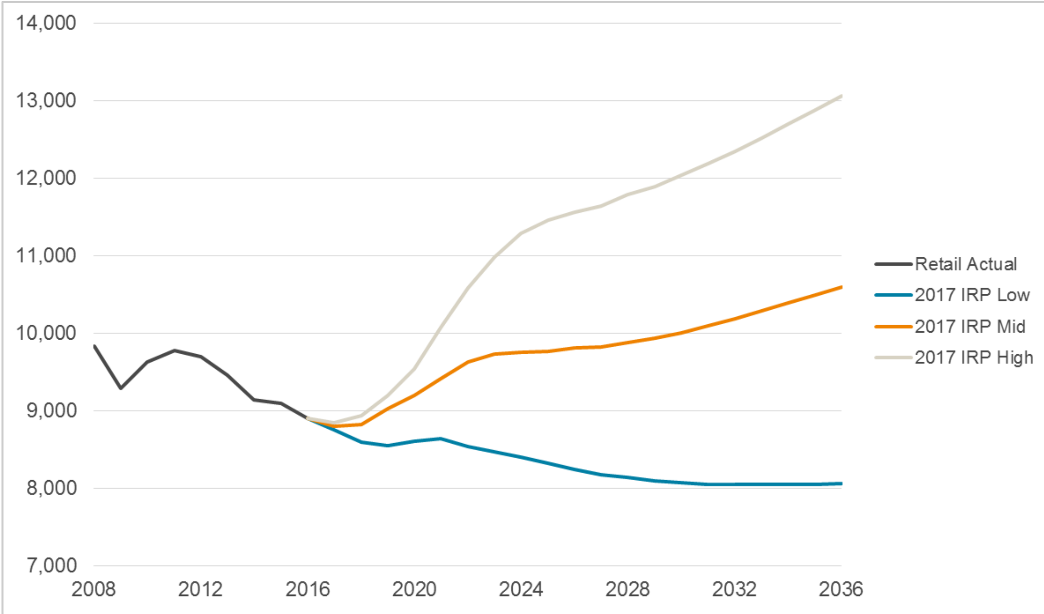
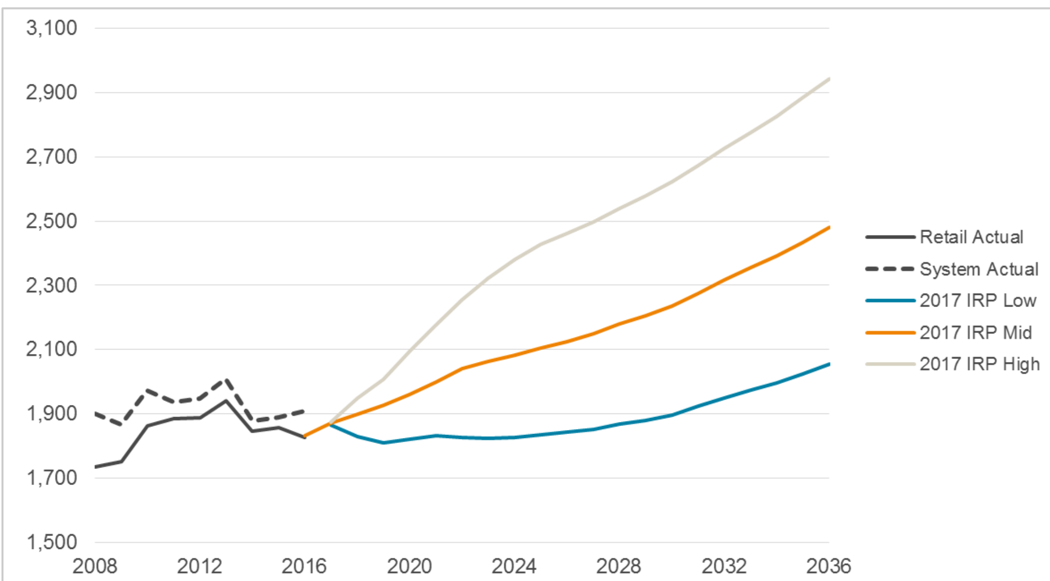


Figure 8. Comparison of PNM's Peak Demand Forecast Sensitivities (MW)



Methodology Overview

The system load forecast includes energy, customers, and peak demand and comprises three parts: retail loads (net of decrements to retail caused by energy efficiency programs, private solar, and new codes and standards), and distribution and transmission losses. The energy forecast is at the detailed rate-class level and aggregated to a total system load. Losses are added at the system level. PNM prepares the peak demand forecast in aggregate at the retail level, and then adjusts it for the impact of energy efficiency programs, private solar, and new codes and standards.

PNM primarily relied upon statistically based time-series modeling to prepare retail load forecasts. This approach incorporated growth in customer loads over time, known customer-specific growth, and near-term impacts of economic activity in PNM's service area. Additionally, individual forecasts were prepared for large customers whose loads are of sufficient size to merit individual review. Specific assumptions for the decrements and for each customer class are described in Appendix A.

Load Forecast Scenarios

Table 3 shows the average 20-year growth rates for the low, mid, and high-load forecast sensitivities developed for this IRP. Note that all forecast scenarios presented here predict slower growth than the baseline presented in the 2014 IRP. This expectation is caused, in part, by the slow rate of economic recovery in New Mexico as well as increased energy efficiency and conservation within PNM’s service territory. Further description of these impacts is provided in Appendix A.

Table 3. Load Forecast Net Growth Rates

Growth Segments	Low	Mid	High
Residential Sector			
Residential Customers	0.00%	0.89%	1.40%
Residential Use Per Customer	-0.98%	0.39%	0.65%
Residential Energy Sales	-0.98%	1.10%	2.06%
Commercial/Industrial Sectors			
Commercial & Industrial Energy Sales	0.05%	1.01%	2.26%
Retail Energy Sales	-0.34%	1.01%	2.12%
Peak Demand			
System Peak Demand	0.51%	1.50%	2.40%

Low-Load Forecast

The low-load forecast represents a combination of zero customer growth and reduced loads across all sectors. This scenario predicts decreasing loads almost continuously through 2036.

For the low-load forecast, PNM assumed negative growth in use per customer for both residential and commercial customers. This could result from increases in energy efficiency savings and increases in private solar installations. The low-load forecast also assumed that industrial energy load growth is limited to the new data center customer, with that customer’s load forecasted at the low end of its current anticipated range. For the demand forecast, which uses the energy forecast as an input variable, the Lower Limit 95% Confidence Level was used to capture the probability that demand could be at this lower limit given the lower energy levels. Table 4 illustrates the low-load forecasts for the years 2017, 2022, and 2036.

Table 4. 2017 IRP Low-Load Forecasts

Forecasts	2017	2022	2036
Demand (MW)			
PNM Forecasted Load Total	1,906	1,963	2,261
EE (incremental)	(23)	(91)	(145)
PV-DG (incremental)	(18)	(45)	(62)
Net System Total	**1,865**	**1,827**	**2,055**
Energy (GWh)			
PNM Forecasted Load Total	8,998	9,460	9,352
EE (incremental)	(197)	(706)	(1,042)
PV-DG (incremental)	(47)	(210)	(251)
Net System Total	**8,754**	**8,544**	**8,059**

Mid-Load Forecast

PNM developed the mid-load forecast using normalized weather and the Bureau of Business and Economic Research at the University of New Mexico's mid scenario for projected economic conditions. The mid scenario of the economic forecast predicts a steady improvement in economic conditions. Industrial energy sales will be positively impacted by the addition of the single data center customer at its load projection.

For the mid-load forecast, moderate residential and commercial customer increases are assumed, with customer count growth of about 0.8%. In this scenario, customer growth does not climb to some of the higher growth rates seen in the 1990s for PNM's service area. The forecast projects use per customer decreasing until about 2030 because of energy efficiency, new codes and standards, and the impact of private solar installations. All of these programs have downward pressure on customer usage. The demand forecast uses the mid energy forecast as an input variable and is estimated with the expected value, which is the value with a 50% chance that the actual demand will be either higher or lower than expected. Table 5 illustrates the mid-load forecasts for the year's 2017, 2022, and 2036.

Table 5. 2017 IRP Mid-Load Forecasts

Forecasts	2017	2022	2036
Demand (MW)			
PNM Forecasted Load Total	1,911	2,163	2,650
EE (incremental)	(23)	(89)	(122)
PV-DG (incremental)	(18)	(33)	(48)
Net System Total	**1,871**	**2,041**	**2,480**
Energy (GWh)			
PNM Forecasted Load Total	9,040	10,475	11,671
EE (incremental)	(197)	(695)	(881)
PV-DG (incremental)	(47)	(153)	(194)
Net System Total	**8,796**	**9,627**	**10,597**

High-Load Forecast

The high-load forecast predicts sustained customer growth of 1.4%. PNM broadly based its assumptions for this scenario as matching customer growth rates observed in PNM Resources' Texas-New Mexico Power Company utility and the scenario assumption that New Mexico's economic recovery eventually matches the rate seen in neighboring Texas. The high-load forecast includes increases in industrial energy sales due to the addition of a second data center. This scenario also includes a slight uptick in use per customer because of reduced impacts of energy efficiency and reduced private solar interconnections. For the demand forecast, which uses the energy as an input variable, Upper Limit 95% Confidence Level was used to capture the probability that demand could be at this higher limit given the higher energy levels. Table 6 illustrates the high-load forecasts for the year's 2017, 2022, and 2036.

Table 6. 2017 IRP High-Load Forecasts

Forecasts	2017	2022	2036
Demand (MW)			
PNM Forecasted Load Total	1,915	2,361	3,076
EE (incremental)	(23)	(85)	(100)
PV-DG (incremental)	(18)	(20)	(34)
Net System Total	**1,875**	**2,257**	**2,943**
Energy (GWh)			
PNM Forecasted Load Total	9,088	11,339	13,924
EE (incremental)	(195)	(660)	(726)
PV-DG (incremental)	(47)	(96)	(137)
Net System Total	**8,847**	**10,583**	**13,061**

PLANNING CONSIDERATIONS

PLANNING CONSIDERATIONS

Reliability and Reliability Standards

The most cost-effective resource portfolio must provide sufficient reserves to maintain system reliability. PNM reviews the ability of the MCEP to provide two categories of reserves: planning reserves and operating reserves. Planning reserves are forecasted generation capacity over and above the amount required to serve the projected peak-hour demand of the year. Operating reserves provide the ability to respond to supply and demand imbalances within each hour. Imbalances can occur due to normal variations in system loads and resources and due to unforeseen events that change the loads and resources balance. Planning reserves are necessary in the event that one or more of PNM's generation resources are unavailable or cannot run at full capacity at the time of system peak. Planning reserves also account for uncertainties in demand forecasting and resource availability. As illustrated in the Load Forecast section of report, actual net-system peaks can vary from the forecasted net system peaks by hundreds of MWs.

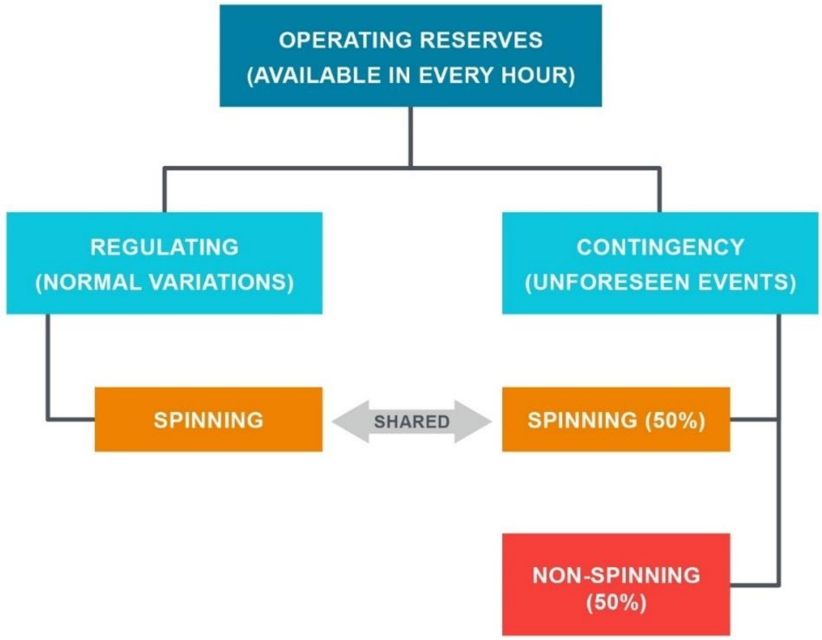
For resource planning, operating reserves and planning reserves must be considered conjunctively in determining a system's resource needs and how best to supply those needs to maintain reliability and meet system peak.

Operating Reserves

Operating reserves, which include contingency reserves that respond to unforeseen events and regulating reserves that respond to load variations, are generating capacity available to the Balancing Authority (BA) system operator to quickly satisfy system requirements when there is a disruption in demand or supply (e.g., a variable energy resource ramping down or a generator tripping offline). Contingency reserves are optimally comprised of spinning and non-spinning reserves (which must be able to respond within 10 minutes) in approximately equal amounts.

The total contingency reserve requirement is based on the utility's single largest generator, also known as the single largest hazard, or associated with either generator or transmission capacity. Non-spinning contingency reserves must be able to respond to cover losses within 10 minutes. PNM also requires regulating reserves, which are typically supplied by spinning resources, to continuously maintain system balance. Figure 9 illustrates the different types of operating reserves needed to respond within any given hour.

Figure 9. Operating Reserves



The MCEP must ensure sufficient resources to meet system operational demands, which can vary by location within PNM's service territory. Operational standards for the industry are established by North American Electric Reliability Corporation (NERC) and the WECC. PNM is a NERC-registered BA, ensuring that the power system demand and supply are balanced in real time as well as managing transfers of electricity with other BAs and must maintain adequate operating reserves to comply with NERC and WECC reliability standards. PNM adheres to the following primary standards for the MCEP:

- BAL-002-1: Disturbance Control Performance Standard
- BAL-002-WECC-2: Contingency Reserves
- BAL-003-1: Frequency Response Requirement

PNM must meet these requirements every hour of every day. NERC, WECC, and PNM's reserve sharing group, the Southwest Reserve Sharing Group (SRSG), can assess monetary penalties for noncompliance. The WECC regional reliability coordinator (Peak RC) can order the utility to shed load if required for the BA to reestablish compliance with these standards.

For a detailed explanation of these standards, refer to Appendix D.

Planning Reserves

Planning reserves are the amount of resource capacity available (as a percentage of total capacity), above and beyond the projected peak loads at the highest demand of the year. Planning reserves are not required to be spinning or non-spinning (available within 10 minutes), and, therefore, can be any type of available capacity. For the MCEP, PNM targets a minimum 13% planning reserve margin as a result of the stipulation approved in NMPRC Case No. 08-00305-UT. Section 9 of that stipulation states:

> Beginning with its 2011 Integrated Resource Plan (“IRP”), PNM will use a planning reserve margin of 13% of peak demand, but not less than 250 MW of planning reserve capacity, for resource planning purposes, instead of the 15% used in the current IRP and as agreed to in Paragraph 18 of the Merchant Plant Stipulation. The Signatories acknowledge that PNM’s actual reserve margin may temporarily deviate from the planning reserve margin due to unexpected changes in load or imbalances caused by the magnitude of new resource additions to meet load growth, system requirements and renewable portfolio standards.

As the stipulation makes clear, the prescribed 13% reserve margin is a target, not a hard and fast rule, and the actual reserve margin may temporarily differ from the target for a variety of reasons, including the need to add resources in increments that do not precisely match immediate on-peak requirements and the need to add resources to meet other system requirements. Due to the impact of more variable energy and variable demand on the system, reserve margin is an insufficient metric to consider system reliability and must be supplemented by other reliability assessments

Typically, industry standards set reliability targets that should produce a system reliability expectation that the utility will experience a loss in firm load event no more than once in every 10 years. This is a common standard and has been widely used in the electric industry for 50 years. Traditionally, the simplest planning metric for modeling this reliability objective has been the reserve margin. Setting a planning reserve margin at a high level will result in a higher level of reliability, which generally implies greater investment in reliable resources.

PNM’s loss of load probability using a 13% reserve margin is higher than two events in every 10 years. Reducing the loss of load probability to two events per year requires a reserve margin of about 17%. Achieving a one-in-10-year probability would require a reserve margin target in excess of 20%, which is much higher than the PNM’s current target. The results of a reserve margin study PNM conducted in 2013 indicate that a good balance between the cost of additional capacity and the desire to reduce loss of load events results in a planning reserve margin of 15% to 17%, reducing the loss of load events to two events every 10 years. PNM is continuing to use the 13% reserve margin target in its capacity expansion modeling and has supplemented that analysis with an analysis of loss of load probability.

Reserve Needs

PNM’s existing portfolio includes nuclear, coal-fired, natural gas-fired, and renewable energy resources. Diversity of resources and fuel sources is beneficial to ensuring system reliability because variabilities in one resource compensate for others. Each of these resource types has different operating characteristics that must be accounted for when PNM is planning system operations on a day-ahead and hourly basis. Each day, PNM develops a unit commitment plan to fully supply projected hourly loads during the day. The first step in the plan is to commit (i.e., schedule) all non-dispatchable or must-take resources including nuclear, wind, solar, geothermal, and the minimum outputs of any base load or other generation unit projected to be needed to serve the daily projected load (e.g., coal-fired generation plus natural gas generation during expected high-load periods). PNM schedules all other generation using economic dispatch principles with the lowest cost generation unit being the first dispatched.

Once the projected hourly load profiles are met using this process, PNM commits additional generation needed to provide reserves including the spinning reserves that provide load following, regulation, voltage support, frequency response requirements, and the contingency reserve obligations of both spinning and non-spinning reserves. Table 7 shows PNM's two largest hazards, the amount of SRSG assistance available, and how much capacity is required to be available within 15 and 60 minutes.

Table 7. Inputs to Operating Reserves Requirements at Time of Summer Peak

Largest Hazards	Size of Hazard (MW)	SRSG Assistance	15-Minute Requirement	60-Minute Requirement
SJGS Unit 4	392	160	232	70
Afton	230	160	70	25

PNM is required to maintain a minimum level of operating reserves (that is, regulating and contingency reserves) that meet NERC and WECC criteria. The required amount of contingency reserves is based on 3% of the BA's load and 3% of the BA's online generation, which is measured and calculated every four seconds. Within the contingency reserve calculation, at least half of the contingency reserves must be carried by generators that are online, unloaded, and able to respond to immediate changes to interconnected system frequency. The required amount of contingency reserves changes hourly. During the peak-load hour, PNM's SRSG spin and non-spin quota is approximately 125 MW, plus enough additional contingency reserves to recover from a failure of PNM's single largest hazard. Regulating reserves are an incremental amount of spinning reserve above this, sufficient to adequately follow load and respond to fluctuations in the output of generating units, most importantly renewable resources. Regulating reserves change hourly based on system variables such as changes in load, renewable generation output, and unscheduled generation changes.

The need for frequency response currently is driven by NERC Standard BAL-003-1. PNM currently estimates that 15 MW of fast frequency response is needed to maintain compliance with the standard.

Environmental Impact and Anticipated Regulations

PNM has a long-standing record of environmental stewardship. Emission rates for each of PNM's existing generation facilities are listed in Table 8.

Table 8. 2016 Emission Rates by Plant

Facility	PNM MWh	lbs/MWh					lbs/TWh*
		NO_X	CO	SO_2	PM_{10}	CO_2	Mercury
Afton Generating Station	598,228	0.135	0.136	0.005	0.062	929.9	n/a
Four Corners Power Plant	878,443	4.722	n/a	1.200	0.068	1,863.9	5.9
La Luz Gas Turbine	22,425	0.089	0.009	0.006	0.027	1,165.7	n/a
Lightning Dock Geothermal	14,255	0.000	0.000	0.000	0.000	0.0	n/a
Lordsburg Generating Station	12,924	1.197	0.724	0.007	0.077	1,378.5	n/a
Luna Energy Facility	277,966	0.094	0.053	0.005	0.026	926.2	n/a
NM Wind Energy Center	498,967	0.000	0.000	0.000	0.000	0.0	n/a
Palo Verde Generating Station	3,291,008	0.000	0.000	0.000	0.000	0.0	n/a
PNM-Owned Solar	256,205	0.000	0.000	0.000	0.000	0.0	n/a
Red Mesa Wind	213,997	0.000	0.000	0.000	0.000	0.0	n/a
Reeves Generating Station	145,621	3.091	0.716	0.008	0.095	1,556.0	n/a
Rio Bravo (Delta) GT	111,841	0.404	0.014	0.008	0.050	1,411.2	n/a
San Juan Generating Station	4,760,528	2.616	2.670	0.512	0.034	2,182.1	0.9
Valencia Energy Facility	63,839	0.403	0.151	0.007	0.198	1,378.5	n/a

*One million MWh

PNM has long been committed to the environment through the efficient SJGS plant design, sourcing its fuel with low-sulfur coal, implementing emission control improvements as they became available and following low-impact operating practices. SJGS complies with EPA's public health standards in accordance with the National Ambient Air Quality Standards (NAAQS). Although the challenge of greenhouse gas (GHG) emissions and climate change remains, PNM's record of improving its total emissions levels will continue with the 2017 retirement of two units at SJGS. Table 9 lists the most recent emission control upgrades installed at SJGS.

Table 9. Impact of Recent Emission Control Upgrades at SJGS

SJGS	NO_x	SO_2	Particulate Matter	Mercury*	CO_2*
Emission Reductions after 2009 Environmental Pollution Control Upgrades	44% ↓	71% ↓	72% ↓	99% ↓	N/A
2012 Emissions ** (tons/year)	21,000	10,500	2,380	0.005	11,906,236
Emission Reductions from 2012 to 2018 (two-unit shutdown)	62% ↓	67% ↓	50% ↓	50% ↓	47% ↓
Permitted Emissions in 2018 (tons per year)	8,011	3,483	1,184	0.002	6,359,750

* Mercury and CO_2 numbers are based on actual emissions since there are currently no required permit limits for these constituents.

** 2012 chosen as base year to match the base year of EPA's Clean Power Plan (CPP) for reduction of CO_2 emissions for fossil generation.

PNM has a current environmental focus in three key areas:

- Meeting regional haze rules at the coal-fired SJGS as cost-effectively as possible while providing additional environmental benefits including a significant reduction in CO_2, nitrogen oxides, sulfur dioxide, particulate matter, and other emissions from existing power plants
- Meeting New Mexico's increasing RPS requirements as cost-effectively as possible
- Increasing energy efficiency program savings and complying with the EUEA requirements

All three of these efforts result in significant CO_2 emissions reductions from historical levels and limit CO_2 emissions going forward. PNM's 2017 IRP considers CO_2 emissions from future portfolios by assigning a range of potential future CO_2 costs and by quantifying potential total emissions from MCEP options. This method of assessing potential carbon costs is supported by the reasonable anticipation of future carbon emission regulations and is required by the IRP rules. The form and stringency of potential future carbon emission regulations or targets are uncertain, as discussed further below.

Other Environmental Regulations

PNM's natural gas-fired electric generating units operate in compliance with Clean Air Act (CAA) Title V Operating Permits issued by the New Mexico Environment Department. New Mexico currently does not have any non-attainment areas, although Dona Ana County may reach a small area of non-attainment due to cross-border transport of air emissions. Gas plants generally have lower emissions levels of NO_x, SO_2, and CO_2 when compared with coal plants. Gas plants' NOx emissions are controlled by low-NOx burners and/or selective catalytic reduction. Catalytic reduction is also used to control carbon monoxide emissions. Ozone control is a potential future emission regulation.

Methane emissions from new oil and natural gas sources are subject to Environmental Protection Agency (EPA) regulation. The regulations generally apply to production, processing, transport, and storage of those fuels. This may be of some impact as it could affect the cost or availability of gas supplies.

The PVNGS is licensed and inspected by the Nuclear Regulatory Commission (NRC). Currently, no new or revised environmental regulations are anticipated during the planning period. PVNGS does not emit GHGs and uses treated sewer effluent for cooling water.

Coal ash (coal combustion residuals) at PNM's coal plants are regulated as non-hazardous waste. Ash at SJGS is returned to the adjacent surface mine for use in reclamation. Water intake structures are subject to rules to protect fish and wildlife in surface water supplies. SJGS is a zero-discharge facility, but is also subject to regulations protecting against storm water runoff or other potential contamination of neighboring waters.

Federal CO2 Emission Regulations

In April 2007, the U.S. Supreme Court held that the EPA has the authority to regulate GHG under the CAA. In December 2009, EPA released its endangerment finding stating that the atmospheric concentrations of six key GHGs (CO_2, methane, nitrous oxides, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride) endanger the public health and welfare of current and future generations.

EPA met President Obama's timeline for issuance of carbon pollution standards for new sources under Section 111(b) and for existing sources under Section 111(d) of the CAA. On August 3, 2015, EPA issued its final standards to limit CO_2 emissions from power plants. The final rule was published on October 23, 2015. Three separate but related actions took place: (1) the final Carbon Pollution Standards for new, modified, and reconstructed power plants were established (under Section 111(b)); (2) the final CPP was issued to set standards for carbon emission reductions from existing power plants (under Section 111(d)); and (3) a proposed federal plan associated with the final CPP was released.

Carbon Pollution Standards for New, Modified, and Reconstructed Power Plants

EPA's final rule to limit GHG from new, modified, and reconstructed power plants establishes standards based upon efficient natural gas combined cycle technology. Newly constructed or reconstructed base load natural gas-fired stationary combustion turbines are limited to 1,000 lbs CO_2/MWh-gross or 1,030 lbs CO_2/MWh-net. A new source is any newly constructed fossil fuel-fired power plant that commenced construction after January 8, 2014.

Clean Power Plan

The CPP rule sets the first compliance date in 2022 and adopts emission targets. The rule establishes two numeric emission standards: one for fossil-steam units (coal- and oil-fired units) and one for natural gas-fired units (combined cycle only). The emission standards are based on emission reduction opportunities that EPA deemed achievable using technical assumptions for three building blocks: efficiency improvements at coal-fired electric generating unit (EGU), displacement of affected EGUs with renewable energy, and displacement of coal-fired generation with natural gas-fired generation. The final standards are 1,305 lbs/MWH for fossil-steam units and 771 lbs/MWH for gas units, both of which phase in over the period from 2022 to 2030. To facilitate implementation, EPA converted the emission standards into state goals. Each state's goal is based on the weighted average of each state's unique mix of affected units.

Table 10 summarizes the New Mexico emissions goals laid out by EPA. The analysis section illustrates CO2 emissions from PNM's operation compared to these goals.

Table 10. New Mexico CO_2 Emissions and EPA Standards

Year	CO_2 Emission Rate (lbs/MWh)	CO_2 Emissions (tons)
New Mexico Current State		
2012	1,798	17,339,683
EPA Standard for New Mexico		
2022	1,325	13,815,561
2030	1,146	12,412,602

While President Trump has announced the administration's intention to abandon the CPP in its current form, the Rule, though stayed in its current form by the Supreme Court, provides a baseline of comparison for where CO_2 emission rates will go with PNM's IRP.

Paris Accords

The United Nations Framework Convention on Climate Change (UNFCCC) is an international environmental treaty that was negotiated at the 1992 United Nations Conference on Environment and Development (informally known as the Earth Summit) and was enforced in March 1994. The objective of the treaty is to "stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system." Parties to the UNFCCC, including the United States, have been meeting annually in Conferences of the Parties (COP) to assess progress in meeting the objectives of the UNFCCC. This assessment process led to the negotiation of the Kyoto Protocol in the mid-1990s. The Protocol, which was agreed to in 1997 and established legally binding obligations for developed countries to reduce their GHG, was never ratified by the United States. At the COP meeting in 2011, participating nations, including the United States, agreed to negotiate by 2015 an international agreement involving commitments by all nations to begin reducing carbon emissions by 2020. On December 12, 2015, the Paris Agreement was finalized during the 2015 COP. The agreement between more than 190 nations requires that countries submit Nationally Determined Contributions (NDCs) reflecting national targets, actions arising from national policies, and elements relating to oversight, guidance, and coordination of actions to reduce emissions by all countries. In November 2014, former President Obama announced the United States' commitment to reduce GHG, on an economy-wide basis, by 26% to 28% from 2005 levels by the year 2025. Further, the U.S. NDC is targeting an 80% economy-wide CO_2 reductions by 2050. The Clean Power Plan is a key element of the U.S. NDC described above.

While President Trump has announced his intention to withdraw the U.S. from the Paris Agreement, it is unclear as of the time of filing this IRP what form the withdrawal will take. Accordingly, while the Paris Agreement was considered in putting together the IRP, the U.S. participation or non-participation in the Paris Agreement is not dispositive for any of the resource planning decisions made in this process.

Modeling Carbon Cost

The near-term outlook for explicit carbon costs has been altered by the 2016 presidential election. Implementation of the CPP is on hold for judicial review and the key provisions are being unwound by the EPA under a new executive order issued by President Trump. Nonetheless, PNM is continuing to model a cost for each ton of CO_2 emitted in each portfolio's projected operation. PNM expects that a replacement for the CPP is likely to be implemented at some point in response to continued international calls that carbon emissions should be addressed.

The replacement regime for the CPP is assumed to again take the form of a per-unit cost (emission tax or cap and trade allowance). A legislative program could address the legal challenge of administrative taxation as well as the other problematic features of the CPP. Such a new program could be politically acceptable, especially if the carbon cost burden is less severe than under the CPP.

PNM also considered several other potential regulations including National Ambient Air Quality Standards (including ozone and nitrogen oxide regulations), natural gas and methane rules that may affect oil and natural gas production, EPA Rule 316(b) addressing cooling water intake structures, the 2015 Waters of the U.S. rule potentially addressing water discharge, and coal combustion residual (aka coal ash) disposal rules.

Cost to Customers

PNM measured “cost to customers” of the IRP portfolio options using the metric required and described in the IRP rule: net-present value of costs required to meet retail customer loads over the 20-year planning period. PNM’s calculation of this metric includes the following:

- Cost to operate and maintain existing resources from 2017 through 2036
- Cost to build, operate, and maintain any resources added between 2017 and 2036
- Costs associated with retiring any resources between 2017 and 2036

While these costs contribute to the overall revenue requirements PNM uses to calculate customer rates, they do not include any credits that might occur from PNM’s off-system sales.

Regulated Utility Considerations

PNM is an investor-owned, vertically integrated regulated monopoly, meaning that PNM is owned by shareholders and is the sole provider of electricity in its service territory. Additionally, PNM owns most of the generation, transmission, and distribution assets utilized to serve its customers and must file rate reviews with the NMPRC for its shareholders to receive a return on investments made to serve PNM customers. PNM must meet requirements to ensure its investments are cost-effective and prudent. The IRP is one of these requirements and provides the public an opportunity to provide input and review the analysis used to decide upon future electricity supply plans.

While the IRP process and resulting plan support building or retiring units, the IRP, does not authorize resource construction or abandonment. PNM must apply for a Certificate of Public Convenience and Necessity (CCN) to obtain approval to place a new generating facility into service. Applicable IRP regulations provide that in any CCN proceeding relating to a NMPRC-accepted IRP, “[e]vidence that the resource is consistent with the IRP, and that there have not been material changes that would warrant a different course of action by the utility, will constitute prima facie evidence that the resource type, but not the particular resource being proposed, is required by the public convenience and necessity.” Accordingly, the accepted IRP and its findings may be relevant in the CCN proceeding, depending upon the facts and circumstances. To retire a unit, PNM must file an abandonment application. Once the NMPRC approves PNM’s application to build or retire a generation facility, PNM will seek recovery of the approved costs through a rate review. When new PNM rates are set, the operational costs of the facility, such as fuel and ongoing labor, are directly passed through to the customer. Customer bills are credited if PNM sells excess power or ancillary services at a profit into wholesale markets.

Generation Ownership Considerations

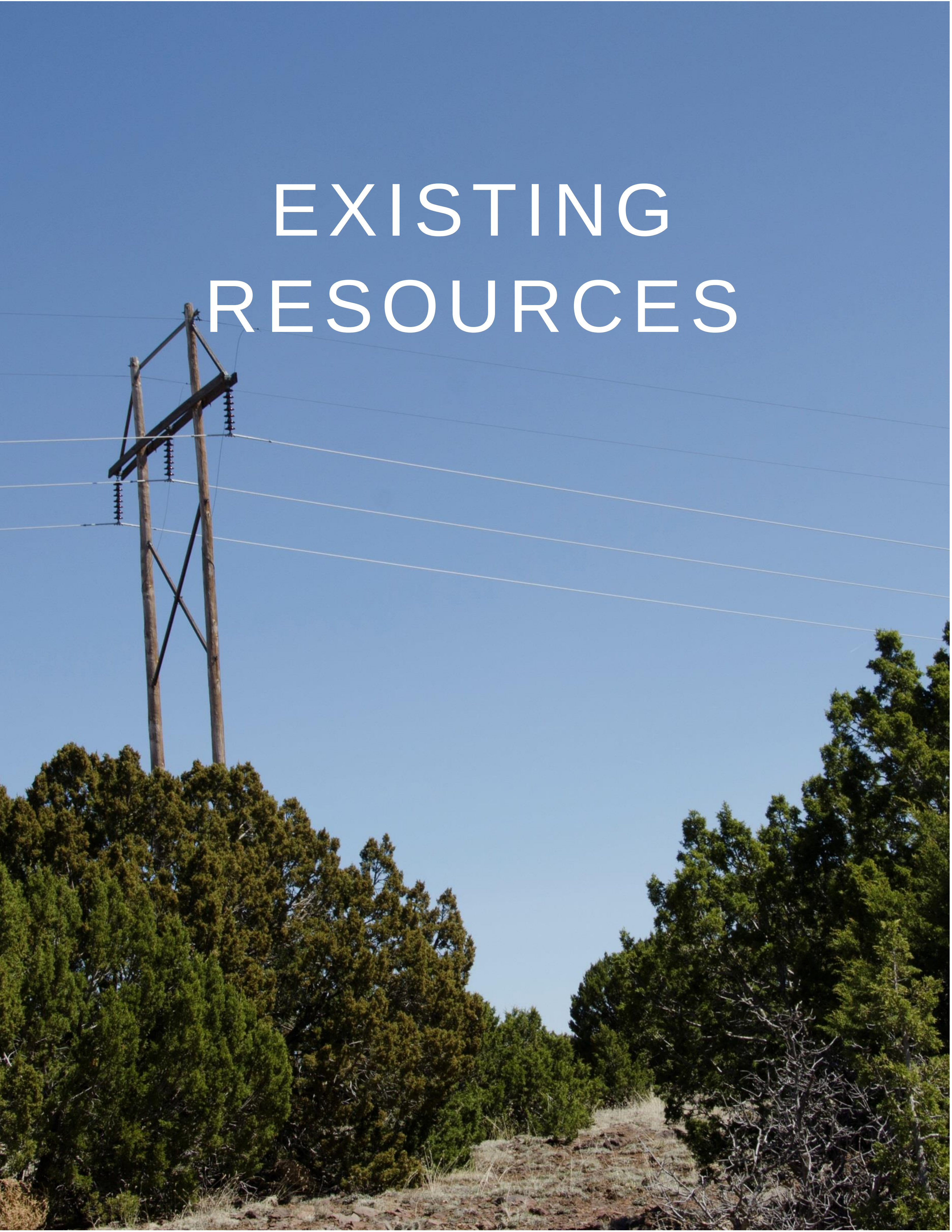
The IRP process requires identification of the “most cost-effective portfolio” based on the net present value of revenue requirements to reliably meet customer demand within regulatory constraints while considering risks and uncertainties.

Providing resources to meet electric demand can take different forms. The analysis completed in this IRP does not assume any particular ownership structure. PNM calculated present value of revenue requirements for new resources based on the best information available for resource costs. Whenever possible, the information is based on recent bids for new resources, whether the bids were for turnkey utility ownership or for independent power producer ownerships with purchase power agreement (PPA) pricing. PNM accepts bids for either structure in its competitive bid process. For example, a “utility self-build” approach occurs when the utility constructs and operates the project on its own. A “build-transfer” or “turnkey” approach occurs when the project is developed to a particular stage or completely constructed by a third party, often an independent power producer, and then sold to the utility to own and operate over the useful life of the generation resource. A third alternative is to purchase the output from a generator or set of generators over a contracted period (Purchased Power Agreement or PPA). Each of these options, while they may have equivalent net present value of revenue requirements based on the assumptions in this IRP, have different risks and uncertainties that should be considered. These are described in Table 11.

Table 11. Generation Ownership Benefits, Risks, and Uncertainties

Ownership	Benefits	Risks and Uncertainties
Utility-Owned	• Lower cost of capital • Construction control and full knowledge to ensure reliability requirements met • Flexibility to respond to changing regulations over time • Ownership and use of depreciated asset available at end of life • Passes cost savings on to customers	• Construction risk • Operational risk
Build-Transfer or Turnkey	• Limited construction risk, but maintains reliability risk	• Higher cost of capital • Operational risk
Power Purchase Agreements	• Price and operational certainty per contract for the contract period • Limited construction and operational risks	• Limited flexibility once the contract is signed • No access to residual asset

EXISTING RESOURCES



EXISTING RESOURCES

Existing Demand-Side Resources

As defined by the IRP Rule, demand-side resources consist of two types: energy efficiency and load management. Energy efficiency generally refers to reductions in energy use by customers. PNM's energy efficiency programs have been shown to be cost effective using the Utility Cost Test (UCT) and have been approved by the NMPRC. Load management programs reduce customer demand at times of peak load or during generation supply shortages. PNM's existing resource portfolio includes the energy efficiency and load management programs approved by the NMPRC pursuant to the EUEA. Amendments to the EUEA in 2013 also require utilities to invest 3% of retail sales revenues in energy efficiency and load management programs. This provides consistency in the level of spending that can be expected over time.

This section describes PNM's existing demand-side energy efficiency and demand response resources, and is responsive to Section 17.7.3.9(C)(9) of the IRP Rule. Demand response is a form of load management.

Energy Efficiency Programs

PNM's current portfolio of energy efficiency programs encourages customers to reduce energy use through the following measures:

- Instant rebates for the purchase of light emitting diode (LED) bulbs
- Rebates for recycling older refrigerators
- Residential incentives for efficient lighting, appliances, and cooling equipment
- Rebates to small and large commercial customers for efficient lighting and heating, ventilating, air conditioning and other energy efficiency improvements tailored to the customers' business
- Incentives for homebuilders to construct homes that go beyond existing energy codes
- Energy saving kits provided to fifth-grade and high school students along with an inter-active instructional presentation on energy efficiency
- Incentives that specifically target energy efficiency improvements for lower-income customers

Once approved by the NMPRC, energy efficiency programs remain in effect until modified or terminated by the NMPRC.

The NMPRC determined these programs were cost-effective using the utility cost test, which calculates a ratio of program benefits to program costs. To be cost-effective, the ratio of benefits to costs must be greater than one. Program benefits include the value of the lifetime avoided energy and capacity, which includes avoided cost of energy production, such as fuel costs and avoided air emissions associated with electricity generation, and avoided or delayed cost of capacity additions.

Total energy efficiency savings achieved is the sum of the effectiveness of each program. Every year, PNM reviews the demand and energy savings from its energy efficiency programs using the results from an annual independent third-party measurement and verification process and estimates the customer participation in current and future programs.

In its load forecast, PNM only counts savings from current energy efficiency programs through their estimated lifetime, but assumes that as the lifetimes of programs expire, existing programs will be replaced with new programs so that demand savings and energy savings will continue throughout the plan period.

Demand Response Programs

Demand response programs reduce customer demand at times of peak load or during generation supply shortages. Existing demand-side resources include two voluntary demand response programs originally approved by the NMPRC in Case No. 07-00053-UT and reauthorized in Case No. 16-00096-UT. The Power Saver program is for residential and small commercial customers with less than 150 kilowatt (kW) load, and the Peak Saver program is for commercial customers with 150 kW of load or greater. The demand response programs are governed by 10-year professional services contracts that began in 2007 and expire in 2017. PNM has filed for reauthorization of the programs in its most recent energy efficiency and load management program plan filing. PNM's DR programs help PNM meet operating reserve requirements since they can be dispatched and synced to the grid within 10 minutes.

Power Saver Program

The Power Saver program is designed for residential customers with refrigerated air conditioning. PNM hired a third-party contractor, Comverge, Inc., to manage this program through 2017. Comverge installs a device on customers' refrigerated air conditioners that PNM uses to remotely control the units when they cycle. During peak periods, PNM can reduce peak demand by remotely cycling the air conditioners, which reduces the collective electricity demand from the air-conditioning units. The program runs during the summer peak period of June through September, and this resource can be dispatched within 10 minutes as a peak-shaving resource for up to 100 hours each year.

Peak Saver Program

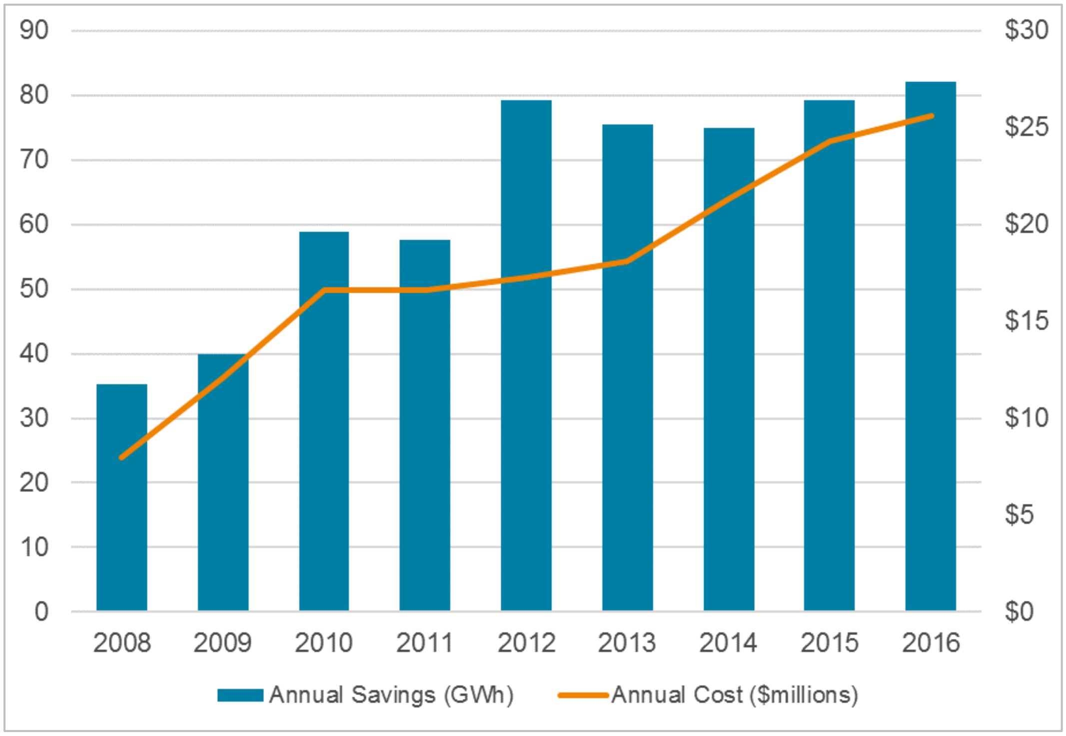
PNM's Peak Saver program is offered to larger commercial and industrial customers with peak loads of 150 kW or greater per month. PNM contracted with EnerNOC to manage this program through 2017. This program targets electric loads that can be reduced during periods of peak system demand (June through September). EnerNOC installs equipment that reduces loads when called upon for up to 100 hours each year.

Energy Efficiency and Demand Response Savings to Date

In accordance with the energy efficiency Rule and the EUEA, PNM filed the first annual PNM energy efficiency and load management program report with the NMPRC on April 1, 2009, and has filed subsequent reports on or about April 1 every year thereafter. The reports include detailed measurement and verification findings as determined by the NMPRC selected independent evaluator, quantified customer adoption rates and energy savings for both energy efficiency programs and demand response programs.

Annual energy savings from PNM energy efficiency and demand response programs is calculated to have reached 82 gigawatt hours (GWh) for 2016. Figure 10 shows the annual energy savings and program costs since 2008 for the total portfolio of programs.

Figure 10. Annual Savings from Energy Efficiency and Demand Response



PNM determines the peak demand savings from the approximately 40,000 Power Saver program participants by use of a statistical sampling method that derives a kW savings factor per installed unit. Hourly meter data is also available for the approximately 110 Peak Saver program participants to determine the demand savings available to PNM. Table 12 shows the verified average peak capacity reductions from the demand response programs for the years 2008 through 2016.

Table 12. Verified Average Peak Capacity Reductions for 2008 through 2016

Year	Demand Response Capacity (MW)
2008	47
2009	53
2010	67
2011	57
2012	57
2013	62
2014	61
2015	59
2016	57

PNM exceeded the 2014 cumulative goal of 411 GWh (5% of PNM's 2005 retail sales) by achieving cumulative savings of 421 GWh and is on track to exceed the 2020 cumulative goal of 658 GWh (8% of 2005 retail sales). Year-to-year results vary based on date of implementation, customer participation, verified savings, and marketing efforts. Table 13 summarizes the results from 2008 through 2016 for PNM's overall demand-side programs on a combined basis. Through 2016, the programs have achieved 583 GWh of cumulative energy savings and 97 MW of cumulative demand savings, not including the capacity savings from the demand response programs shown separately in Table 12 above.

Table 13. PNM DSM Program Combined Results (2008-2013)

Year	Annual Energy Savings (GWh)	Cumulative Energy Savings (GWh)	Cumulative Demand Savings (MW)
2008	35	35	8
2009	40	75	14
2010	59	134	24
2011	58	192	33
2012	79	271	47
2013	76	346	59
2014	75	421	71
2015	79	501	83
2016	83	583	96

Demand-Influencing Rates and Tariffs

PNM designs rates, tariffs, and demand response and energy efficiency programs to offer customers economic incentives to either shift energy use to off-peak periods, thereby increasing the system load factor, or to reduce system demand and energy through demand-side management. Improving the system load factor results in improved utility asset use and lowers overall system costs. PNM promotes energy efficiency programs and efficient energy-use incentives through bill inserts, direct mail advertising, radio, television, print advertising, and community education programs. The PNM website also provides information on these programs.

The IRP implicitly considers the ongoing impact of rates on PNM's resource needs through the load forecast, which, being based on customer usage patterns, captures the effects of these rates on usage. PNM modeled growth in participation in the Power Saver and Peak Saver programs in the same way as for the existing and projected energy efficiency resources.

According to New Mexico state statute, "rate" and "rate riders" refer to every rate, tariff, charge, or other compensation for utility service rendered or to be rendered by a utility, as well as any rules, regulations, and requirements related to the rate or rate rider. PNM incorporates load management and load-shifting concepts into several rates and tariffs, and this information is provided as part of the response to IRP Rule Section 17.7.3.9 (F) (3). These include the following:

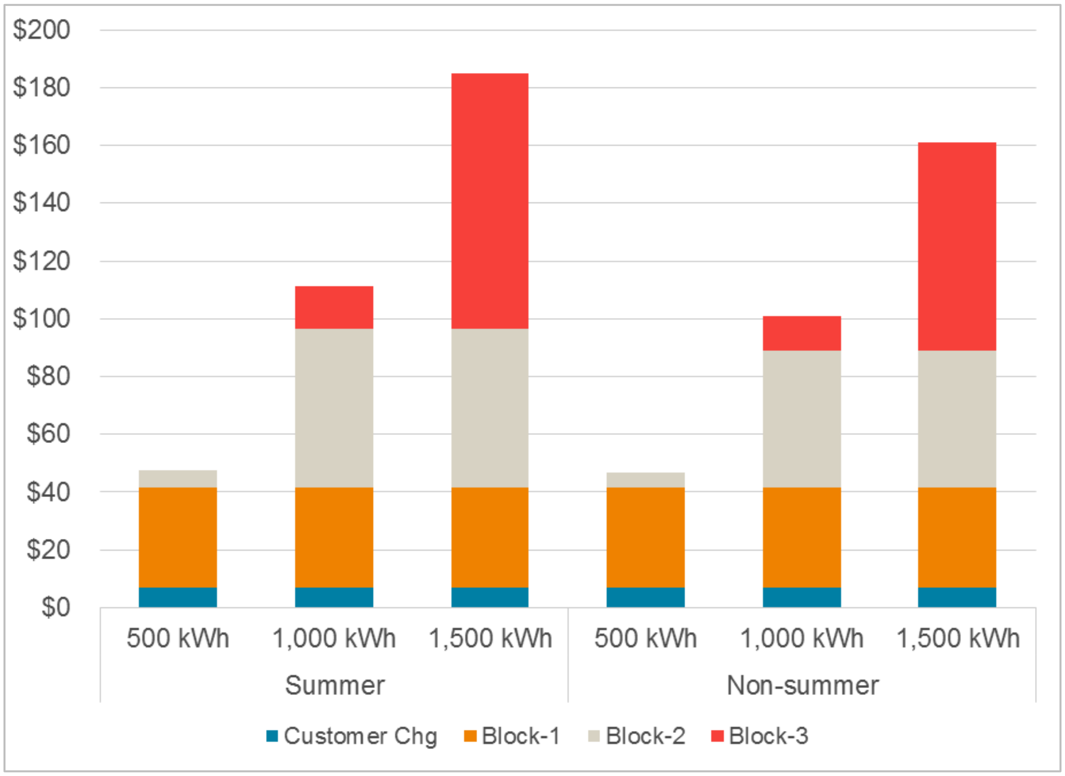
- Inverted Block Residential Rate Design
- Seasonal Rate Design for all PNM tariffs
- Time of Use Rates
- Demand Rates for Commercial and Industrial Tariffs

- Incremental Interruptible Power Rate
- Voluntary Demand Response Programs

Inverted Block Residential Rate Design

Rates per unit of energy increase for residential customers as usage increases (Rate 1A). This is designed to discourage higher usage by increasing the customer's bill as consumption increases. Figure 11 shows an example of increasing energy block rates for usage.

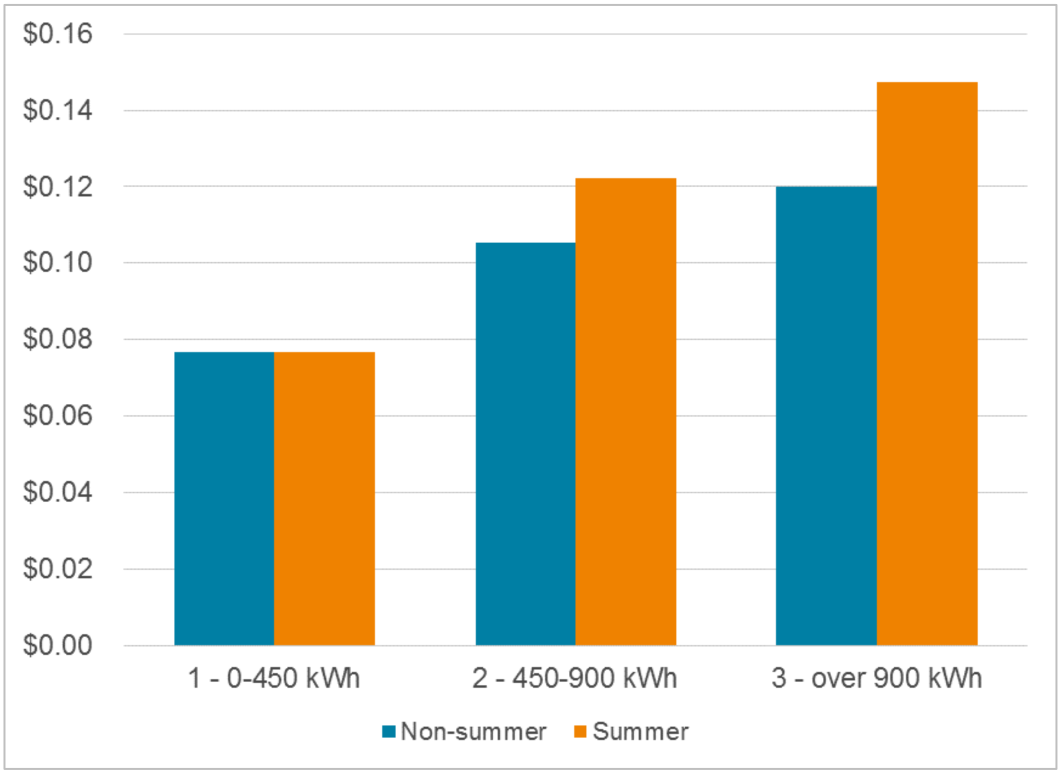
Figure 11. Increasing Energy Block Rates



Seasonal Rate Design

Summer rates are higher than winter rates for most customer classes. This seasonal rate design encourages customers to moderate usage during the summer months when demand on the system is greatest and utility generation costs are highest. By discouraging usage during the peak season, seasonal rates help to delay the need for new resources. Figure 12 also illustrates this rate design.

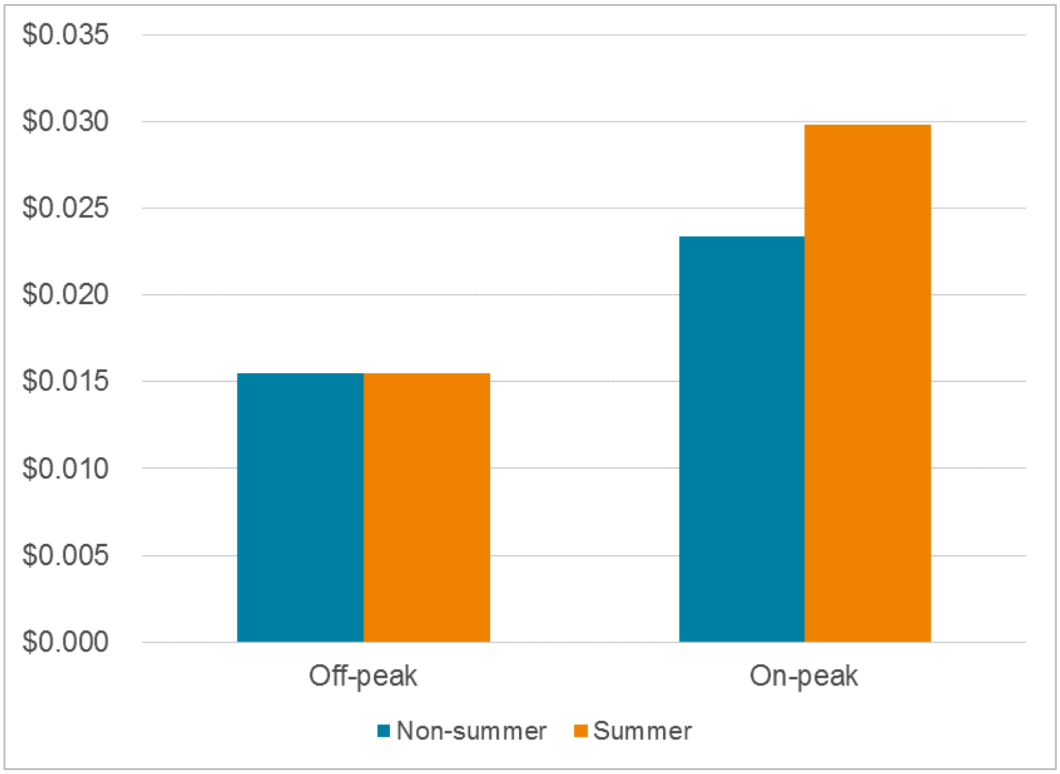
Figure 12. Seasonal Rates



Time-of-Use Rates

PNM offers time-of-use (TOU) rates for Residential (1B), Small Power (2B), General Power (3B & 3C), Large Power (4B), Large Mining (5B), Irrigation (10B), Water Sewage Pumping (11B), Universities (15B), Large Manufacturing (30B), Station Power Service (33B), Large Power Service (35B), and Special Service Rate—Renewable Energy Resources (36B) customer classes. These rates encourage customers to avoid usage during the time when the cost to serve is highest (on-peak) and allow for greater efficiencies in generation resource utilization. TOU rates are required for all larger customers (greater than 50 KW). The remaining customers can choose TOU rates to lower their cost by shifting usage to off-peak periods. Figure 13 shows how PNM's rates differ between on- and off-peak during summer and non-summer periods.

Figure 13. TOU Rates



Demand Rates

Demand rates charge for on-peak usage during a specific time window. A customer who uses a high rate of power for short periods places “demands” on the system to be ready with capacity at any time to provide that power. Demand rates encourage customers to reduce power usage during on-peak hours and to shift usage to off-peak hours, which improve system utilization and efficiency and can defer the need for investment in capacity additions.

Incremental Interruptible Power Rate

Five General Power and three Large Power customers have contracts for service under an interruptible power tariff (PNM’s Rate Rider 8). In the event of a system emergency, PNM can call upon these customers to interrupt their incremental on-peak billed demand with 30 minutes’ notice during the on-peak period from 8:00 a.m. to 8:00 p.m., Monday through Friday. Interruptions can extend for up to two hours into the daily off-peak period, but have no limit in the total hours of interruption per year. A customer may bypass an interruption request and will forgo the monthly tariff discount afforded to them, but if the customer fails to interrupt more than two times during any calendar year, the customer will be permanently removed from the rider.

Voluntary Demand Response Programs

Under the energy efficiency rider, residential and business customers (under PNM’s Power Saver program) and business customers with a demand greater than 150 kW (under PNM’s Peak Saver program) can volunteer to have portions of their load curtailed upon 10-minute notice from June through September, for up to 100 hours per year. This load shifting helps PNM manage peak summer loads.

Existing Generating Resources

PNM's supply portfolio consists of diverse generating resources that are owned by PNM or that generate power purchased by PNM through a PPA. PNM constructs or contracts supply resources to serve customer loads, to replace expiring contracts or retiring facilities, and to meet public policy requirements such as the RPS. Appendix J includes cost and performance data for PNM's existing resources.

Table 14 lists PNM's existing and operating generation resources. A detailed discussion of each of these resources follows.

Table 14. PNM's Existing Generation Resources

Resource Name	MW	Fuel	PNM-Owned or PPA
San Juan Generating Station[3]	783	Coal	Owned
Palo Verde Generating Station[4]	268	Uranium	Owned/Leased
Afton Generating Station	230	Natural Gas	Owned
Four Corners Power Plant	200	Coal	Owned
New Mexico Wind Energy Center	200	Wind	PPA
Luna Energy Facility	189	Natural Gas	Owned
Reeves Generating Station	154	Natural Gas	Owned
Valencia Energy Facility	150	Natural Gas	PPA
Rio Bravo Generating Station	138	Natural Gas or Oil	Owned
Red Mesa Wind Energy Center	102	Wind	PPA
Lordsburg Generating Station	80	Natural Gas	Owned
PNM-Owned Solar (multiple sites on distribution system)	107	Solar	Owned
La Luz Energy Center	40	Natural Gas	Owned
Dale Burgett Geothermal	4	Geothermal	PPA

Existing Renewable Resources

PNM's renewable resources include three types of facilities: wind, solar, and geothermal, all described below.

New Mexico Wind Energy Center

The New Mexico Wind Energy Center (NMWEC) is a 200-MW wind energy generation facility located near House, New Mexico. It interconnects to the PNM transmission system at the Taiban Mesa station interconnected to the Blackwater-BA 345-kV line and can deliver up to 200 MW into PNM's system. Since 2003, PNM has purchased the renewable energy and the

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[3] Beginning in 2018, Units 2 & 3 of SJGS will be retired. PNM's capacity at SJGS will be reduced to 497 MW at that time.
[4] Beginning in 2018, PNM's 10.2% of Palo Verde Generating Station Unit 3 will begin retail service, increasing capacity from Palo Verde to 402 MW.

associated RECs generated by the NMWEC from its owner and operator, NextEra Energy, Inc., under a 25-year PPA that expires in 2028. In its current renewable energy procurement plan filing, PNM has proposed repowering this facility, which would extend the PPA to 2045.

Red Mesa Wind

Red Mesa Wind, LLC, is a 102-MW wind energy generation facility located about 50 miles west of Albuquerque in Cibola County, New Mexico. Owned by NextEra Energy, Inc., the facility interconnects to PNM's 115 kV transmission facilities at the Red Mesa station west of Albuquerque. PNM has purchased the energy and associated RECs generated by this facility since January 1, 2015, under a 20-year PPA that expires in 2035.

The amount of annual wind energy generation is difficult to predict for NMWEC and Red Mesa because it varies with wind activity. Historical data (Table 15) show that production at NMWEC can range from 405 GWh to 579 GWh per year. PNM forecasts that NMWEC will generate approximately 525 GWh per year and that Red Mesa Wind will generate approximately 208 GWH per year. Repowering NMWEC is estimated to increase the average generation by 105,000 MWh per year.

Table 15. Historical Wind Production Generation and Capacity from 2003–2016

Year	NMWEC		Red Mesa		Total	
	MWh	Capacity Factor	MWh	Capacity Factor	MWh	Capacity Factor
2003	211,931	N/A			211,931	N/A
2004	514,414	29.3%			514,414	29.3%
2005	513,019	29.3%			513,019	29.3%
2006	528,567	30.2%			528,567	30.2%
2007	500,420	28.6%			500,420	28.6%
2008	577,506	32.9%			577,506	32.9%
2009	533,289	30.4%			533,289	30.4%
2010	552,242	31.5%			552,242	31.5%
2011	579,900	33.1%			579,900	33.1%
2012	546,321	31.1%			546,321	31.1%
2013	493,949	28.2%			493,949	28.2%
2014	489,442	27.9%			489,442	27.9%
2015	404,765	23.1%	184,297	21.0%	589,062	22.4%
2016	492,427	28.0%	214,030	24.4%	706,457	26.8%

PNM-Owned Universal Solar Resources

PNM currently has 107 MW of universal solar PV-generating facilities in service. The solar PV resources consist of a mix of fixed-tilt and single-axis tracking arrays located near various communities in PNM's service area: Alamogordo, Albuquerque, Deming, Los Lunas, Las Vegas, Rio Rancho, Bernalillo County, Cibola County, Otero County, Santa Fe County, and Valencia County.

PNM dedicates 1.5 MW of these solar facilities to PNM's Sky Blue program. The solar-generated energy is blended with generation from NMWEC to supply customers participating in the Sky Blue program. Table 16 lists PNM's existing owned resources.

PNM has requested approval for an additional 50 MW of universal solar in its current renewable energy plan filing.

Table 16. PNM-Owned Universal Solar Resources

Resource Name	Location	In-Service	Nameplate Capacity (MW)
Fixed Tilt Resources			
Prosperity Battery/Solar	Albuquerque	2011	0.5
Reeves Station	Albuquerque	2011	2.0
Los Lunas	Los Lunas	2011, 2013	7.0
Las Vegas	Las Vegas	2011	5.0
Deming	Deming	2011, 2013	9.0
Alamogordo	Alamogordo	2011	5.0
Manzano	Valencia	2013	8.0
Otero County	Otero County	2013	7.5
Single-Axis Tracking Resources			
Sandoval	Rio Rancho	2014	6.1
Meadowlake	Valencia	2014	9.1
Cibola County	Cibola County	2014	7.6
South Valley	Albuquerque	2015	10.0
Rio Communities	Valencia	2015	10.0
Santolina	W. Bernalillo	2015	10.5
Santa Fe County	Santa Fe County	2015	9.5

In addition to the solar facilities described above, PNM owns two small PV systems installed before 2007: a 25-kW installation located in Algodones, New Mexico, and a 5-kW installation at PNM's Aztec office facilities located in Albuquerque.

PNM-Owned Universal PV/Battery Demonstration Project

As part of the Department of Energy's Smart Grid Storage Demonstration program, PNM was selected as one of 16 participants nationwide to demonstrate the integration of renewable energy and energy storage. The Prosperity Energy Storage project was the first to come online and has been in operation since September 2011. It is one of the most successful demonstration projects of battery storage and PV energy in the nation, and has been the subject of extensive research and facilitated development of smart grid concepts in cooperation with the University of New Mexico, Northern New Mexico College, Ecoult/East Penn Manufacturing, and Sandia National Labs. Located in Albuquerque near Mesa del Sol, this 500-kW PV and 1-MWh-rated battery facility has continually demonstrated the ability to simultaneously smooth the intermittency of the PV output, while shifting PV output to peak periods.

The project is also one of the most highly instrumented PV and storage systems in commercial operation and is gathering one-second-interval data from more than 200 locations on the panels. These data are coupled with a sophisticated back-office control system and computer models of the utility grid to continually refine controls and create an optimized dispatchable renewable resource—one that could have an on-peak capacity contribution of 100%. Functionality has been added to allow for reliability-based peak shaving and wholesale market arbitrage.

Dale Burgett Geothermal Facility

The Dale Burgett Geothermal Facility (formerly known as Lightning Dock Geothermal) generates electricity using geothermal resources and is located in the Animas Valley in Hidalgo County, about 20 miles southwest of Lordsburg, New Mexico. PNM purchases the energy and associated RECs under a 20-year PPA. PNM began purchasing power from this facility in January 2014. Initially, operations began at the 4-MW level with the facility to increase its production up to the 10-MW level. PNM’s current renewable energy procurement plan requests authority to increase the projected output from this facility in beginning in 2019. The plant uses a closed-loop binary system where geothermally heated groundwater is pumped from a deep reservoir to a heat exchanger. Heat is transferred to a working fluid with a low boiling point in a separate closed-loop system. The working fluid flashes and powers the turbine expander, generating electricity, and is then cooled and condensed back into a liquid to be used again. The groundwater is re-injected into the same deep reservoir to be naturally reheated without ever coming into contact with the secondary working fluid or being exposed to air.

Existing Thermal Resources

PNM’s existing thermal-generating resources consist of two coal-fired resources (SJGS and FCPP), PVNGS, and seven natural gas-fired generating stations. PNM assesses natural gas requirements for its natural gas-fired generating plants monthly, taking into consideration the anticipated load, weather, and other events, such as outages in the generating fleet, and makes purchases of gas for the upcoming month that can be supplemented with a spot purchase as necessary during the month.

SJGS

The SJGS is a coal-fired plant that consists of four units. Located in Waterflow, New Mexico, SJGS is about 18 miles west of Farmington, New Mexico. The SJGS units were constructed under the following timeframes: Unit 1 in 1976, Unit 2 in 1973, Unit 3 in 1979, and Unit 4 in 1982. At the end of 2017, Units 2 and 3 will be retired.

PNM is the plant majority owner and is the plant operator. Table 17 shows the ownership by generating unit following the retirement of the two units. PNM’s ownership share of Unit 4 represents the largest single resource (497 MW) in PNM’s balancing area. SJGS is PNM’s largest source of base-load generation and is delivered to PNM loads over several PNM-owned transmission lines in northern New Mexico.

Table 17. 2018 SJGS Ownership by Unit

2018 SJGS Ownership	Unit 1 (MW)	Unit 4 (MW)	Total	Percentage
Utility Owner				
PNM	170	327	497	58.7%
Tucson Electric Power	170	0	170	20.1%
City of Farmington	0	43	43	5.1%
Los Alamos County	0	37	37	4.3%
UAMPS	0	36	36	4.2%
PNM Merchant	0	65	65	7.7%
Total	**340**	**507**	**847**	**100.0%**

The coal needed to fuel SJGS is purchased from an adjacent underground coal mine owned by the Westmoreland Coal Company. PNM oversees the administration of the coal contract, which runs through June 30, 2022.

FCPP

The FCPP in Fruitland, New Mexico, consists of two coal-fired units (Units 4 and 5) that are operated by Arizona Public Service Company (APS). PNM's 13% share of these units, which it acquired in 1969 and 1970, respectively, amounts to a total of 200 MW of baseload capacity. Table 18 shows the ownership by generating unit at the FCPP.

Table 18. FCPP Ownership

2017 FCPP Ownership	Unit 4 (MW)	Unit 5 (MW)	Total	Percentage
Utility Owner				
Arizona Public Service	485	485	970	63%
Four Corners Acquisition	54	54	108	7%
PNM	100	100	200	13%
Salt River Project	77	77	154	10%
Tucson Electric Power	54	54	108	7%
Total	**770**	**770**	**1,540**	**100%**

The coal supply for FCPP is the adjacent surface mine owned by Navajo Mine Coal Company, LLC.

PNM relies upon the transmission system to deliver the power from the FCPP into the northern New Mexico system to deliver to New Mexico loads.

PVNGS

PVNGS is a three-unit nuclear power plant located west of Phoenix in Wintersburg, Arizona, that went into service between 1986 and 1988 and is operated by APS. On April 21, 2011, the Nuclear Regulatory Commission approved an application to extend the operating licenses of all units at the PVNGS for an additional 20 years. Unit 1 was extended to 2045, Unit 2 through 2046, and Unit 3 through 2047. Table 19 lists the PVNGS participants, and leased and owned amounts of capacity that PNM controls.

Table 19. PVNGS Ownership by Unit

PVNGS Station	Unit 1 (MW)	Unit 2 (MW)	Unit 3 (MW)	Percentage
Utility Owner				
Arizona Public Service	382	382	382	29.1%
Salt River Project	229	230	230	17.5%
El Paso Electric	207	208	207	15.8%
Southern California Edison	207	208	207	15.8%
SCPPA (SoCal Public Power)	77	78	77	5.9%
LADWP (Los Angeles)	75	75	75	5.7%
PNM	134	134	134	10.2%
Total	**1,311**	**1,315**	**1,311**	**100.0%**

PNM has capacity rights equivalent to 10.2% of the rated output of each of the three units (approximately 134 MW each). In 1985 and 1986, PNM undertook sale/leaseback financing of its Unit 1 and Unit 2 holdings. These units were placed in service during 1986. During the intervening years, PNM has bought back 154 MW of that lease-financed capacity. Currently, PNM owns 30 MW in Unit 1 and 124 MW in Unit 2; PNM continues to lease the remaining 104 MW in Unit 1 and 10 MW in Unit 2. The remaining leases for PVNGS Unit 1 and Unit 2 originally had terms expiring in 2015 and 2016. PNM had options to extend the leases or to purchase the leased interest in those units. PNM has exercised those extension options for the Unit 1 and Unit 2 leased capacity. The extended Unit 1 leases have an expiration date of January 15, 2023. The extended Unit 2 lease has an expiration date of January 15, 2024. At the expiration of these extended leases, PNM has the option to purchase leased assets at fair market value upon the expiration of the extended lease.

PNM owns the full 134-MW share of PVNGS Unit 3, with no lease provisions. In Case 13-00390-UT, the NMPRC granted PNM a Certificate of Convenience and Necessity (CCN) to provide that resource as a supply resource to serve New Mexico retail customers. Beginning in 2018, this capacity will be available to meet jurisdictional customer demand into 2047.

PNM relies on jointly owned transmission facilities and contracted transmission rights that have been secured for delivery of energy from PVNGS to serve retail loads in New Mexico. The transmission rights to bring PVNGS generation to New Mexico, as well as the long-term fuel contracts, are expected to extend throughout the planning period. The fuel supply for PVNGS is procured by APS under multiple agreements for uranium concentrate, conversion, enrichment, and fuel assembly fabrication. Suppliers are selected through a competitive bid process. These contracts are with five separate suppliers to ensure diversity of sources and to mitigate supply reliability risks.

Afton Generating Station

The Afton Generating Station is a 230-MW natural gas-fired generating plant. Afton is located near La Mesa, New Mexico, within PNM's southern New Mexico load pocket and consists of one General Electric (GE) Frame 7 gas turbine, a heat recovery steam generator, and a steam turbine. The plant can be operated either in a simple cycle mode using a combustion turbine or as a combined cycle generating facility. Energy generated at Afton Generating Station can be delivered to southern New Mexico loads or to northern New Mexico loads via contracted transmission rights. Natural gas is transported and delivered to the Afton facility via the El Paso Natural Gas Company's southern main line.

Lordsburg Generating Station

Lordsburg Generating Station (Lordsburg) is a natural gas-fired peaking facility located near Lordsburg, New Mexico. Lordsburg has two GE LM6000 aeroderivative units that can deliver a total of 80 MW of quick-start peaking capacity. PNM needs the quick-start capability of Lordsburg for system load balancing and regulation. Located in the southern New Mexico load pocket, energy from Lordsburg can be delivered directly to southern New Mexico loads or can be delivered via contracted transmission rights to PNM's northern load. PNM has contracted with NAES to operate and maintain Lordsburg under a service agreement. Lordsburg receives natural gas supply via the El Paso Natural Gas southern main line.

Luna Energy Facility

The Luna Energy Facility (Luna) is a natural gas combined cycle plant constructed in 2006 near Deming, New Mexico. This facility is configured with two GE heavy-frame 7FA gas turbines, each connected to a HRSG steam generator. PNM owns one-third, or 189 MW, of Luna. Tucson Electric Power Co. and Samchully Asset Management, LLC each also own one-third interests in Luna. In 2008, the NMPRC granted a CCN to make PNM's share of Luna a jurisdictional resource. Unlike Afton Generating Station, Luna can only operate in combined cycle mode. Luna can deliver to southern New Mexico loads directly or, via contracted transmission rights, to PNM's northern load. PNM oversees the plant operation and maintenance on behalf of the owners through a long-term service agreement with NAES, which operates and maintains the plant. Luna receives natural gas supply via the El Paso Natural Gas southern main line in New Mexico. Each owner purchases its own fuel supply.

Reeves Generating Station

The Reeves Generating Station is located southwest of the Paseo del Norte and Jefferson intersection in the city of Albuquerque. The 154-MW facility is a natural gas steam electric plant comprised of three units. Unit 1 became operational in 1958 and has a 44 MW steam turbine generator. Unit 2 became operational in 1958 and has a capacity of 44 MW and Unit 3 became operational in 1962 and has a 66-MW capacity. PNM operates the Reeves Generating Station not only to meet generation requirements, but also to relieve transmission constraints and provide system voltage support. During 2010 and 2011, PNM overhauled Units 1 and 2 and installed new distributed control systems to increase reliability and prolong the life of these units. PNM is addressing the aging of this facility through ongoing maintenance programs and has factored in required maintenance to reach the end of the planning period. Because of Reeve's location within the northern New Mexico load center, it is a critical PNM load-side generating resource for load to relieve transmission system constraints and to provide voltage support in the Albuquerque metro area.

Rio Bravo Generating Station

Rio Bravo Generating Station (formerly called Delta-Person) is a natural gas-fired generating plant with a capacity of approximately 138 MW located on the south side of Albuquerque off Interstate 25. This station consists of a GE 7F combustion turbine that went into service in 2000.

In June 2013, the NMPRC approved a CCN for PNM to acquire the plant from its previous owner.

Because of Rio Bravo's location within the northern New Mexico load center, it is a critical PNM load-side generating resource for load to relieve transmission system constraints and to provide voltage support in the Albuquerque metro area. Rio Bravo is a dual-fuel facility. It operates on natural gas supply delivered through the New Mexico Gas Company; however, when required, the plant can operate on fuel oil stored on-site. PNM anticipates that Rio Bravo will be available to meet customer load throughout the planning period.

Valencia Energy Facility

The Valencia Energy Facility (Valencia) is located south of Belen, New Mexico. Its generator is a heavy-frame GE 7FA gas turbine that began commercial operations on May 30, 2008. It supplies PNM with approximately 150 MW of peaking capability under a 20-year PPA with Southwest Generation, LLC. The PPA expires in 2028. PNM will review options to replace the capacity or extend the contract as the expiration date nears. Valencia receives its natural gas fuel supply through a four-mile-long pipeline interconnection to Transwestern's interstate pipeline.

La Luz Energy Center

The La Luz Energy Center (La Luz) is the newest thermal generator in PNM's portfolio and came online in 2016. The plant is located in Valencia County, directly west of PNM's Belen Substation. Comprised of one GE LM6000, La Luz can deliver 40 MW of capacity into the northern New Mexico load center. It is equipped with selective catalytic reduction and carbon oxidation air emission control systems and can provide full power within 10 minutes to meet operating reserve requirements. Natural gas supply for La Luz is delivered through Transwestern's interstate pipeline. The plant is also close to the El Paso Natural Gas Company's interstate pipeline.

Operational Information for Existing Supply Resources

The IRP Rule Section 17.7.3.9 (C) (1-3, 5-7) requires a description of the resources used by the utility to meet jurisdictional retail load at the time of filing. Table 20 and Table 21 provide this information for PNM-owned and contracted supply-side resources.

Table 20. PNM-Owned or Leased Supply-Side Resources

Generating Resource	In-Service Date	Retirement Date	Location	Unit Capacity (MW)	PNM Capacity (MW)	Ownership Share Percentage	Fuel Type	Duty Cycle	Quick start Capability (MW)
Palo Verde Unit 1	1986	2045	Wintersburg, AZ	1,314	134	10.2%	Nuclear	Base	
Palo Verde Unit 2	1986	2046		1,314	134				
Palo Verde Unit 3	1988	2046		1,314	134				
San Juan Unit 1	1976	2053	Waterflow, NM	340	170	50%	Coal	Base	
San Juan Unit 2	1973	2017		340	170	50%			
San Juan Unit 3	1979	2017		497	248	50%			
San Juan Unit 4	1982	2053		507	195	38.5%			
Four Corners Unit 4	1969	After 2036	Fruitland, NM	770	100	13%	Coal	Base	
Four Corners Unit 5	1970			770	100				
Afton CC	2007	After 2036	La Mesa, NM	230	230	100%	Natural Gas	Intermediate	
Luna CC	2006	After 2036	Deming, NM	567	189	33%	Natural Gas	Intermediate	
Rio Bravo	2000	After 2036	Albuquerque, NM	138	138	100%	Natural Gas	Peaking	21
Lordsburg Unit 1	2002	After 2036	Lordsburg, NM	40	40	100%	Natural Gas	Peaking	40
Lordsburg Unit 2	2002	After 2036		40	40				40
La Luz	2015	2045	Belen, NM	40	40	100%	Natural Gas	Peaking	40
Reeves Unit 1	1960	After 2036	Albuquerque, NM	44	44	100%	Natural Gas	Peaking	
Reeves Unit 2	1959			44	44				
Reeves Unit 3	1962			66	66				
Solar Photovoltaic	Various	2041–2044	Various	107	107	100%	Solar	Intermittent	
Total					**2,323**				**141**

Table 21. PNM Purchase Power Agreements

Resource	In-Service Date	PPA Expiration	Location	Capacity (MW)	Purchase Share	Fuel Type	Duty Cycle
Valencia Energy Facility	2008	2028	Belen, NM	158	100%	Natural Gas	Peaking
NM Wind Energy Center	2003	2028	House, NM	204	100%	Wind	Intermittent
Red Mesa Wind	2010	2046	Cibola County, NM	102	100%	Wind	Intermittent
Dale Burgett Geothermal	2014	2039	Animas, NM	4	100%	Geothermal	Base
Total				**468**			

The capacity listed in the tables is expected to be fully available to meet PNM's system load and reserve margin requirements after the identified in-service date. For renewable resources, the capacity values depend on the amount of capacity they provide at peak, and so the peak contribution capacity values are used for reserve margin planning. For example, the NMWEC wind resource is modeled as providing 5% of its installed capacity during summer peak, and fixed-tilt solar resources provide 55% of their installed capacity as peak load capacity contribution.

The amount of generation capacity from existing resources can change over time because of events such as the expiration of leases and PPAs. PNM's resource plan accounts for such developments and assumes that the resource availability will either be extended or replaced through a competitive bid process.

Changes in the Existing Portfolio from the 2014 IRP

Since the 2014 IRP was filed in July 2014, PNM's existing generation fleet has experienced several changes to the generating plants and the capacity values published in that report. These are summarized below by generation plant:

- Addition of La Luz: In 2016, the La Luz Energy Center came online and is providing quick-start generation capacity in the Albuquerque load center. This unit provides contingency reserves, either non-spinning when it is not generating or the potential for spinning when it is generating.
- SJGS: At the end of 2017, SJGs Units 2 and 3 will be retired from service. This will reduce PNM's capacity from its largest baseload generator by 286 MW and reduce the number of spinning shafts that provide regulating reserves by two.
- Rio Bravo Generating Station: PNM purchased the Rio Bravo plant (formerly known as Delta, or Delta-Person). This facility has and continues to provide 138 MW of peaking capacity.
- Luna Energy Facility: Operational settings have been modified to allow duct burner operation at full rated duty. These changes increase PNM's share of available capacity from 185 MW to 189 MW.
- Valencia Energy Facility: Valencia installed additional equipment that results in a higher available capacity. The capacity has been increased from 145 MW to 150 MW.
- Beginning in 2018, PNM's interest in PVNGS Unit #3 (134 MW) will become part of PNM's capacity under NMPRC jurisdiction. Currently that capacity is excluded from PNM's rate base and the power and energy are not available for NM customers.
- PNM has added 63 MW of universal solar capacity. These facilities are installed at seven sites in PNM's service territory and utilize single axis tracking solar technology.

Existing Transmission System

PNM's transmission system has undergone dramatic changes in its configuration and uses since its inception in 1920 and is largely unchanged since 1985. The initial system consisted of 46 kV and 115 kV lines used to deliver "locally" generated energy to "local" loads. In the 1950s and 1960s, lines between the cities began to be built so local generators could provide backup support to each other, and an associated increase in reliability of service was attained. PNM's first tie to the “outside world” was by way of a 230 kV line to Four Corners built in 1962, concurrent with APS construction of the original FCPP.

The basic 345 kV transmission system that is in place today was developed in the late 1960s and early 1970s as the larger coal-fired generating units at FCPP and SJGS were brought online. This shifted large base-load generation from local to remote resources away from load centers, partly because of environmental, economic, water, and fuel availability considerations, whereas smaller and less efficient intermediate and peaking units were located within the load centers. The availability of remote resources with a mix of low-cost coal and nuclear fuel resulted in the dispatch of generating plants near the load centers was generally only needed during peak hours of the summer or when transmission system import limits would otherwise be exceeded. Economics drive the maximum use of energy brought in from the more efficient and larger remote generators.

The last PNM backbone transmission line was completed in 1984 when PNM constructed the Eastern Interconnection Project, a 216 mile, 345 kV line from the Placitas area north of Albuquerque located at BA 345 kV Switching Station to Clovis, New Mexico, interconnecting PNM with Southwestern Public Service (SPS) in the eastern grid through the Blackwater AC-DC-AC converter station. During the 1990s, PNM pursued the Ojo Line Extension (OLE) project to complete a third 345 kV path from the Four Corners area to the major load centers to reinforce the 345-kV backbone transmission system and increase import capability into the northern New Mexico system. Ultimately, the CCN for permission to build the OLE project was denied and PNM focused its efforts on transmission reinforcements that maximized the use of the existing northern New Mexico system transmission lines.

The “backbone” of the system consists of the 345 kV lines and 230 kV line built in the 60’s and 70’s that emanate from the Four Corners area in northwest New Mexico and run to the Southeast and South. Power flow on these lines is typically from north to south due to the location of base load generation resources in the Four Corners area and in Arizona.

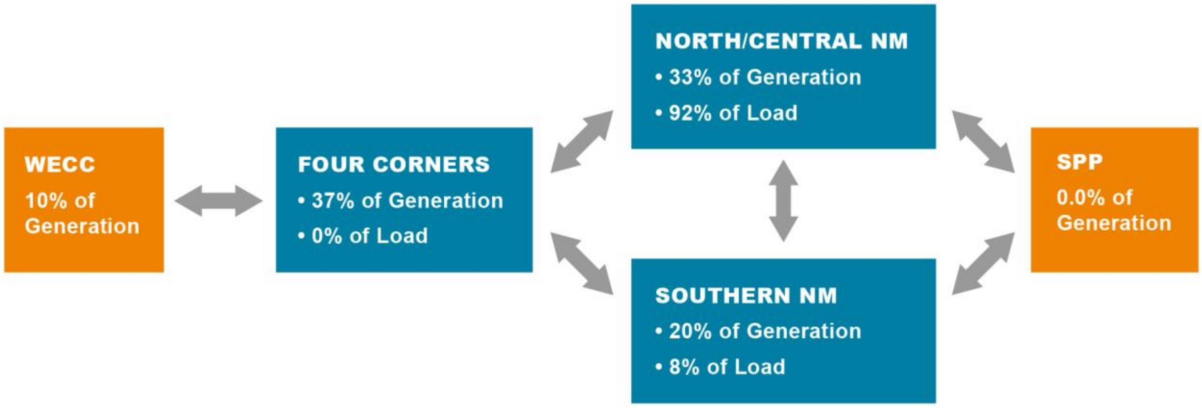
In southern New Mexico, PNM is a joint owner in two 345 kV lines that run from eastern Arizona to the Southeast and East towards El Paso, Texas. PNM also has 25 MW of wheeling rights in a 345 kV line owned by El Paso Electric that runs from Albuquerque to Las Cruces, NM. Historically, power has flowed in an easterly and southerly direction on these 345 kV lines. However, with the significant addition of new generation resources in southern New Mexico over the past several years, flow patterns have changed and power flows can be very light into southern New Mexico when the generation in the south is online and running.

Large autotransformers located at load centers are used to step down the system voltages to the 115 kV level. Substations located on 115 kV, 69 kV and 46 kV lines further step the voltages down to distribution system voltages for delivery to end users.

Existing Transmission Capabilities

PNM’s loads and generation locations are illustrated in the block diagram in Figure 14. The majority of the PNM load (92%) is located in north and central New Mexico, while 47% of PNM’s resources are located at the Four Corners transmission hub, or beyond, and transmitted, or wheeled, to load centers in north and central New Mexico. Although physical connections exist between PNM and the Southwest Power Pool (SPP) to the east, no firm resources are currently being imported from the SPP grid to serve PNM load.

Figure 14. High-Level PNM Transmission System Diagram

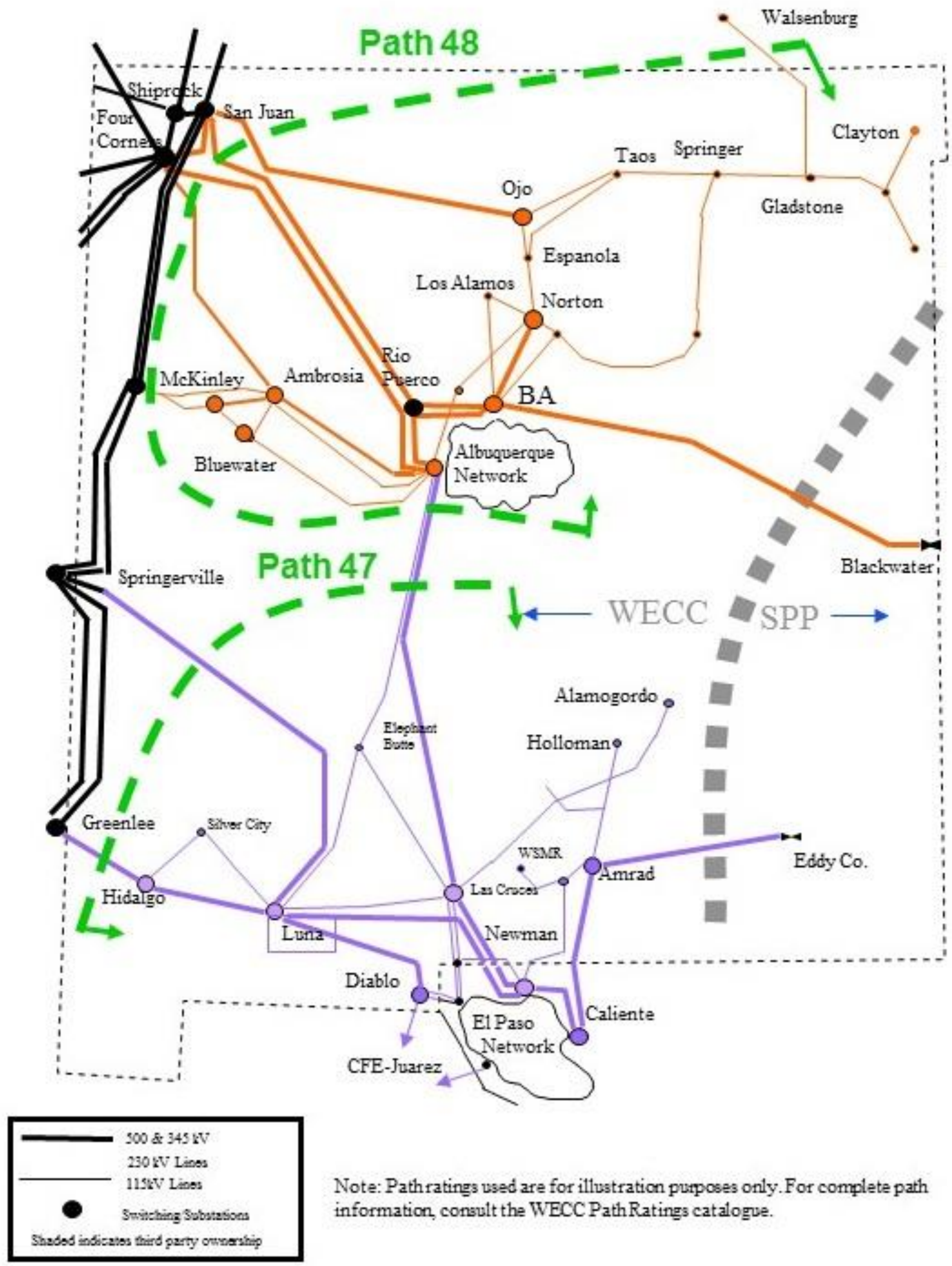


The major transmission lines owned by PNM were primarily developed to deliver remote resources from the Four Corners area of New Mexico to retail and wholesale customers near the load centers in northern and southern New Mexico. Appendix E includes a list of PNM's transmission facilities.

PNM monitors key transmission paths to ensure the transmission system is operated safely and reliably. Established path limits identify maximum flow levels for safe and reliable operation, allowing for the loss of a major element (e.g., line, transformer, and tie point) to occur without disrupting service to customers. In most cases, customers never know when a transmission system element is out of service.

In New Mexico, there are two key transmission paths (called Path 47 and Path 48) that are defined in the planning and operation of the transmission system. Path 48 describes transmission lines in the northern part of the state, shown as orange lines, and Path 47 describes transmission in the southern part of the state, shown as purple lines, as illustrated in Figure 15. Black and grey colored lines represent transmission that is external to that of Path 47 or Path 48. Assets within each path comprise a combination of lines or stations that PNM owns or leases. Any transaction that takes place on the PNM system with neighboring systems is bound by the operation of these paths.

Figure 15. Map of WECC Transmission Path 47 and Path 48



Because of the configuration of the New Mexico system (i.e., the locations of the loads, generation, and major transmission lines), a large portion of the power used to serve PNM and its transmission customers' load flows across the northern New Mexico system, independent of where it is generated. All generation transmitted to PNM load in North Central New Mexico, from the Four Corners area and the western grid, flows on the northern New Mexico system.

Generation resources in southern New Mexico are also delivered to customers in the northern New Mexico system across Path 47.

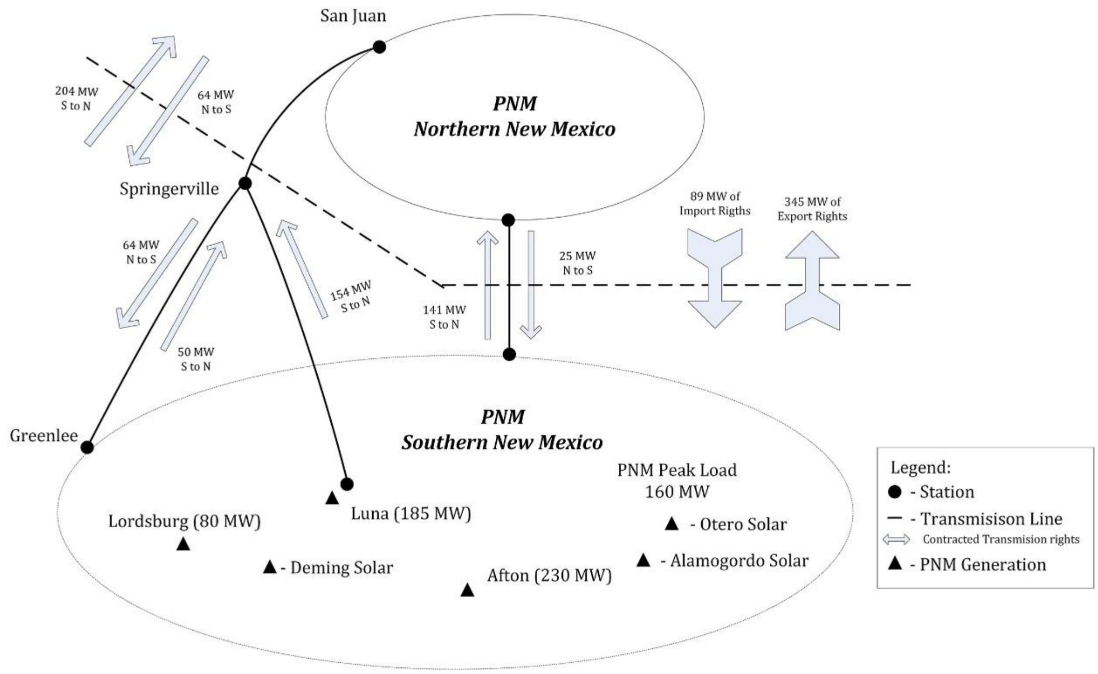
PNM's capacity in Path 47 and Path 48 is fully committed. Transferring existing firm resources and any new resources sited that require transmission along these paths will need to include a transmission system expansion. Resources located on the load side within Path 47 or Path 48 typically help or enhance the operation of these paths by providing a local resource to reduce constraints on these paths. When load increases and Path 48 approaches its import limit, these additional resources can be dispatched to support the system from within a path.

Siting, permitting, cost, and construction timelines for new transmission line projects will continue to be a challenge. The use of load-side generation will continue to play a role in supporting the system and alleviating transmission constraints barring any future barriers to this type of operating practice.

Southern New Mexico Transmission System

PNM's southern New Mexico system, which includes PNM's ownership share in Path 47, delivers power to a combination of jurisdictional service territories which include Deming, Silver City, Lordsburg, Alamogordo, and Ruidoso. The southern New Mexico system also contains three solar facilities and three natural gas fired generation facilities at Afton, Luna, and Lordsburg that PNM integrates into its resource portfolio to effectively dispatch and serve load while minimizing overall utility costs. In addition to PNM's ownership share in Path 47, PNM purchases wheeling over EPE's system to deliver power to a portion of the load served in the Alamogordo area and from TEP for a portion of the load in the Deming area and purchases wheeling from EPE and TEP to move a portion of southern New Mexico generation to northern New Mexico. Figure 16 illustrates the relationship between PNM's southern New Mexico and northern New Mexico import/export rights on the transmission system. These power delivery rights exist over a combination of PNM, Tri-State, and EPE assets. Arrows in Figure 16 indicate the direction of transmission rights between PNM's northern and southern systems that can be utilized to integrate southern New Mexico resources into the entire PNM system. In addition to PNM's ownership share in Path 47, PNM purchases wheeling over EPE's system to deliver power to a portion of the load served in the Alamogordo area and from TEP for a portion of the load in the Deming area and purchases wheeling from EPE and TEP to move a portion of southern New Mexico generation to northern New Mexico.

Figure 16. Southern New Mexico Transmission System



Afton, Luna, and Lordsburg generation resources provide a total of 495 MW of capacity. Because they are located inside the Path 47 transmission boundary, these resources can adequately serve loads in southern New Mexico, with the ability to deliver power to northern New Mexico via 285 MW of transmission rights when needed.

Currently, there are ample generation resources in southern New Mexico to serve all PNM loads in the southern New Mexico system. In addition, PNM currently possesses rights to approximately 89 MW of transmission resources for delivering power from northern New Mexico to southern New Mexico across the Path 47 transmission boundary.

Wheeling Agreements

PNM purchases transmission services to serve PNM's retail customer load and wholesale customer requirements from APS, Tri-State, EPE, and TEP. PNM has executed long-term Firm Point-to-Point Transmission Service agreements with El Paso Electric, Arizona Public Service, Tucson Electric Power and Tri-State G&T and PNM has the right to continue long-term taking that firm transmission service in accordance with FERC policy. These services are described below.

Transmission Services Purchased by PNM from APS

PNM has two transmission service agreements with APS for delivery of PNM's PVNGS energy to New Mexico. The first purchase is a non-OATT bilateral contract for a 130 MW path and the second is an additional 10 MW of transmission service under APS' OATT for service from the Phoenix to Four Corners. In addition, PNM has secured 135 MW of transmission service from APS to bring Palo Verde Unit 3 to Four Corners starting January 1, 2018 as a PNM jurisdictional resource.

Transmission Services Purchased by PNM from Tri-State

PNM purchases network service from Tri-State under Tri-State's comparability OATT for PNM's retail load in the Town of Clayton, in northeastern New Mexico. PNM has interconnections with Tri-State at Ojo Station north of Santa Fe and at Storrie Lake, north of Las Vegas, New Mexico. PNM delivers power and energy to Tri-State at these interconnections for service to Clayton on Tri-State's system. The Clayton load is approximately 3.5 MW.

Transmission Services Purchased by PNM from EPE

PNM purchases firm point-to-point transmission service under EPE's OATT as follows:

- PNM has 295 MW of transmission rights to deliver resources located in southwestern New Mexico to northern New Mexico.
- PNM has 25 MW of transmission rights to deliver resources located in northern New Mexico to southwestern New Mexico.

Transmission Services Purchased from PNM by TEP

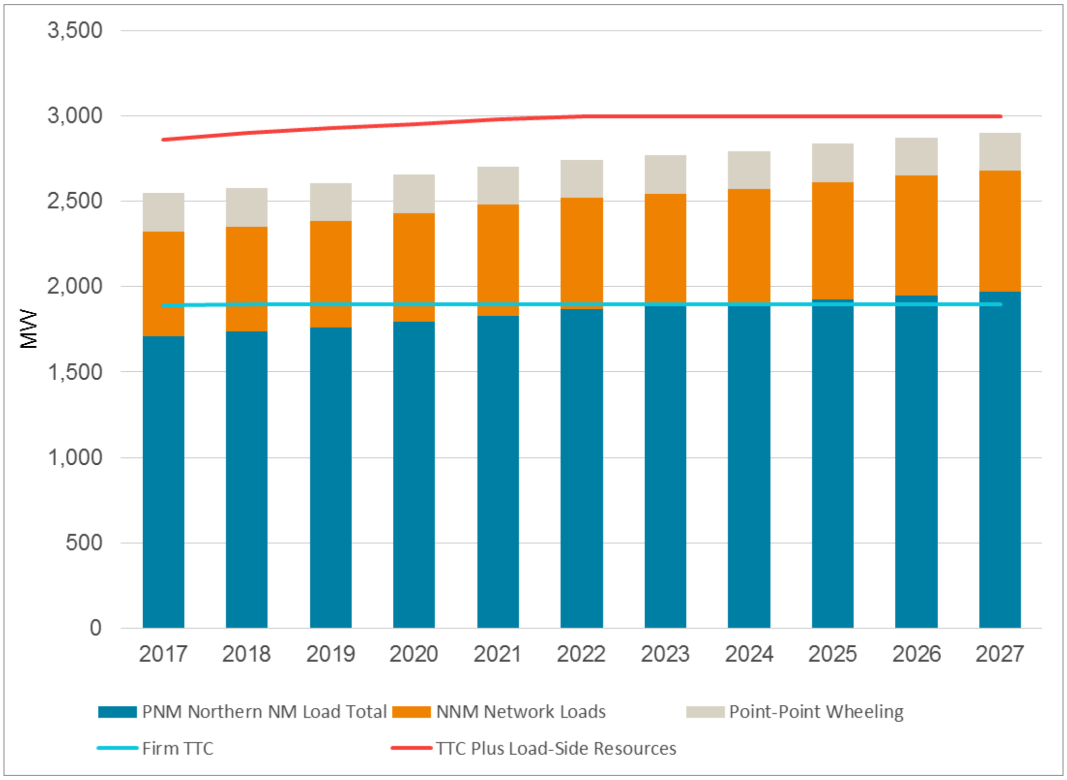
PNM purchases 14 MW of firm point-to-point transmission service under TEP's OATT from SJGS to Greenlee to support system deliveries in southern New Mexico.

Transmission Service Exchange Agreements between PNM and WAPA

PNM has a transmission service exchange with WAPA for delivery of PNM's PVNGS generation output to New Mexico. WAPA provides PNM 134 MW of transmission service from Phoenix to Four Corners. In exchange, PNM receives some revenue and provides 247 MW of transmission service from Four Corners to various points of delivery on PNM's transmission system for WAPA.

The amount of load that can be served by imported power over the northern New Mexico transmission system is equal to the Total Transfer Capability (TTC) of 1896 MW, as shown in Figure 17. The total amount of load that can be served (Load Serving Capability) in northern New Mexico is the sum of imported power and northern New Mexico generated power. The Load Serving Capability is indicated by the purple line in Figure 17. Figure 17 illustrates that, sufficient transmission capacity is expected through 2027.

Figure 17: Transmission Import Limits Relative to Existing Northern NM Generation



Currently, there are ample generation resources in southern New Mexico to serve PNM's southern New Mexico system loads. In addition, PNM currently possesses rights to approximately 89 MW of transmission resources for delivering power from northern New Mexico to southern New Mexico across the Path 47 transmission boundary.

PNM currently has 345 MW of transmission rights to deliver resources located in southern New Mexico for delivery to PNM loads in northern New Mexico. To integrate additional southern New Mexico resources to serve northern loads will require PNM to secure additional transmission rights from the south to the north (San Juan).

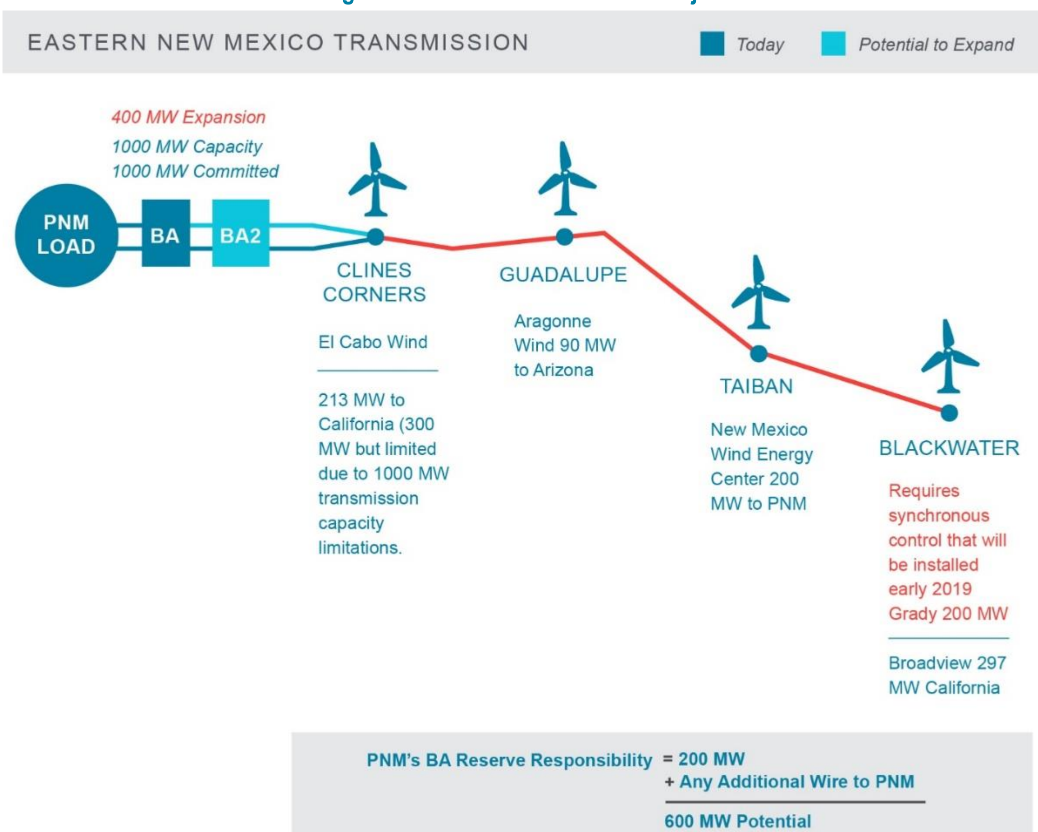
Resources sited near the loads are generally not restricted by transfer capability, but can still require transmission improvements to address local network overload or voltage problems because increased flows result from the new resources. Improvements are specific to each interconnection location and should be individually reviewed. Existing resources along with existing large generation interconnection agreements commitments in the Los Lunas and Belen area of Valencia County will utilize all remaining transmission capacity to move power out of the area. Beyond these identified levels, PNM's studies show that additional resources will create transmission congestion unless transmission capacity between Valencia County and Albuquerque is expanded.

Eastern New Mexico Transmission System

In New Mexico, wind resources are concentrated in the eastern portion of the state. Several wind energy centers have already been developed in this area, including the New Mexico Wind

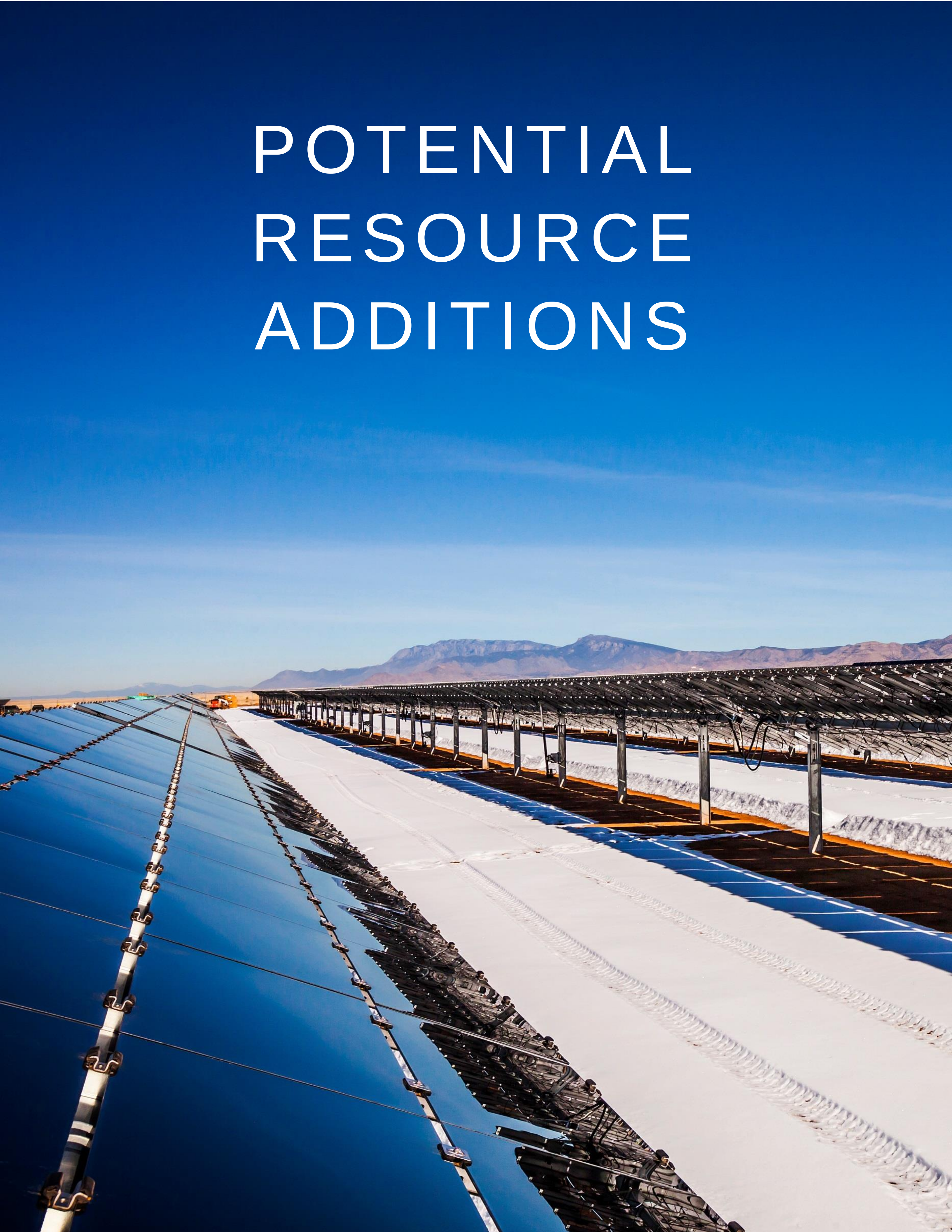
Energy Center (200 MW) and Aragonne Mesa (90 MW). Both of these projects interconnect to PNM's 216 mile 345 kV transmission line from the BA 345 kV switching station (north of Albuquerque) to PNM's Blackwater 345 kV Station (in the Clovis-Portales area of eastern New Mexico), known as the Eastern Interconnect Project (EIP). Three additional New Mexico wind farm projects have entered into power purchase agreements with customers in California and have acquired or are in the process of acquiring transmission service from PNM. Pattern Energy Group, Inc. has developed the Broadview wind farm (297 MW) that interconnects to PNM's Blackwater station near the Texas border and plans to develop a second wind farm called Grady (200 MW) that will interconnect to their transmission line that is interconnected PNM's Blackwater station. Avangrid is developing the El Cabo wind farm (298 MW) that will interconnect to PNM's EIP line near Clines Corners in April 2017.

Figure 18. Eastern Interconnect Project



The addition of these wind farms, along with the existing wind farms, will result in 1000 MW of requested transmission service on the EIP line. As a result, PNM will be installing a voltage support device, a Static VAR Compensator ("SVC"), to the EIP line scheduled to be in service in March 2018 to accommodate these projects' transmission service needs. In addition, a synchronous condenser (i.e., essentially a generator without the turbine to provide synchronous current compensation) will be required at Blackwater station to offer the remaining of transmission service to the Grady windfarm.

POTENTIAL RESOURCE ADDITIONS



POTENTIAL RESOURCE ADDITIONS

The IRP Rule says that, if approved, an IRP provides *prima facie* evidence as to the type of resources PNM requests to add to its portfolio in the future. PNM has developed a list of commercially available resources and emerging technologies expected to be commercially available in the near future for analysis. Selection of any of the representative resources in the MCEP is an indication of the correct type of resource for the future portfolio under the pricing and operation assumptions assumed in the analysis. Following the IRP, PNM will conduct a resource acquisition solicitation to determine the best resource within the type identified.

Over the 20-year planning horizon used in this IRP, it is likely that new resource technologies will be developed affecting both supply-side and demand-side resource options. Some of these technologies may already be known, but not yet commercially available or cost-effective; some may not yet be known. However, development of a 20-year MCEP is based on available and presently known technology. In three years PNM will conduct another IRP and resource options and technologies will be re-characterized and new portfolios will be analyzed at that time.

Future Energy Efficiency Resources

PNM modeled the impact of energy efficiency throughout the planning period. The projected energy and demand savings are based on the following assumptions:

- Current programs, as well as new programs, continue to be approved by the NMPRC.
- Successful identification and implementation of new programs required to meet the EUEA net savings requirements of 8% of 2005 retail sales by 2020 (658 GWh). The projected impact results in savings that meet or exceed the EUEA minimum target savings in 2020.
- PNM will invest 3% of applicable retail revenues annually on energy efficiency and load management programs, as specified in the EUEA.
- Assumptions regarding the maturation of energy-efficient technologies, specifically, the cost of procuring future savings, will increase at an average annual rate of 4.0%.
- Recognizing that the actual escalation rate of the cost of energy efficiency per kWh saved may vary from the projected rate of 4.0%, PNM included two sensitivity cases that assume higher and lower escalation rates over time of 6.0% and 2.0%, respectively.

Future Demand Response (DR) Resources

PNM engaged in a strategic planning effort beginning in 2016 for its demand response programs, including assessment of potential enhancements and growth and administering a Request for Proposals (RFP) process. This planning effort included completing a demand response potential study. The study found that demand response potential in the range of 60 to 80 MW is available. Achieving that potential will require expanding the programs to ensure programs are available to all customers and using technologies such as automated meters to reduce implementation costs. The DR RFP process resulted in selection of vendors to enhance the existing Peak Saver and Power Saver programs, consistent with the potential study, and manage implementation in the 2018-2022 period.

The Peak Saver program targets non-essential peak electric loads and is available to 50 kW or greater commercial and industrial customers. Participating customers receive an incentive based on their level of load reduction at the end of each control season. Over the next five years, the Peak Saver program will retain all of the same program elements that are currently available to customers with the addition of better energy usage and monitoring options for participants. As possible, many participant sites will be automated to improve load monitoring and control and to provide easy access to energy usage data. The automation will allow for integrating a large number of smaller loads to make demand response attractive to small and medium size customers which will allow for participation growth.

The PNM Power Saver program targets residential customers and small commercial customers not served under the Peak Saver program. This program cycles non-critical loads, such as refrigerated air conditioning units, on and off during summer peak hours in exchange for a modest incentive paid at the end of each control season. Over the next five years, PNM expects to grow the program by offering a Wi-Fi thermostat option to customers who have previously dropped out as well as new participants. Customers with existing thermostats will also be allowed to participate under the bring-your-own-thermostat (BYOT) option. Wi-Fi enables a more enhanced customer experience by interactively engaging the customer via any internet connected device (such as a mobile phone or computer). Participants can have a thermostat provided and installed at no charge or enroll in the program using their own qualifying thermostat. In either case, control events initiate through interacting with the thermostats through the participants' home Wi-Fi networks. The thermostat option will provide the additional benefits of potential energy savings through using verifiable setback strategies and providing a higher level of customer satisfaction.

Supply Resource Options

The IRP considers all feasible resources, including current and developing new resource options. This section includes a discussion of each potential resource option, its feasibility of being implemented during the planning horizon, and fuel assessment. PNM has identified and included several generation resource types in the analysis for possible inclusion in the 20-year portfolio plan. Costs for each resource included all associated fuel and operating expenses for existing resources and revenue requirements for new resource alternatives. A discussion of the resource alternatives, along with a narrative describing each resource, is provided below. Appendix D contains cost and performance data for new supply-side resource options.

Renewable Portfolio Standard Resource Additions

The Renewable Portfolio Standard (RPS) for investor-owned electric utilities in New Mexico steps up from 15% to 20% in 2020. PNM already meets the 15% current standard and will require additional renewable resources to meet the 20% standard in 2020. On June 1, 2017, PNM filed its annual Renewable Energy Procurement Plan (REPP). The plan filing includes requests for production increases from the NMWEC and Dale Burgett facilities and an additional 50 MW of single axis tracking universal solar. The combination of these three requests should supply sufficient RECs for compliance with the 20% standard in 2020. PNM assumed this plan will be approved in the assumptions for capacity expansion modeling as part of this IRP. The resource modifications and new solar additions described here are included in the MCEP.

Data Center Resource Additions

As discussed in the "Customers, Load Forecast" section, the load forecast assumes the recently announced data center will expand through 2023. The data center is committed to matching its energy demand with renewable energy production. As the facility expands, PNM expects to add additional renewable energy resources with a mix of wind and solar resources to match the data center's energy use. The incremental list is shown in Table 22.

Table 22. Incremental Wind and Solar to Meet Data Center Loads

Year	Solar PV (MW)	Wind (MW)
2018	30	50
2019	40	0
2020	30	50
2021	30	50
2022	40	30
2023	20	0

Table 23 shows the 2016 PNM generation fuel mix.

Table 23. 2016 Total Generation by Fuel Type

Resource Type	MWh	% MWh
Nuclear	3,291,008	29.5%
Coal	5,638,971	50.6%
Gas	1,232,844	11.1%
Wind	712,964	6.4%
Solar	256,205	2.3%
Geothermal	14,255	0.1%
Total	11,146,247	100.0%

At the time this report was written, the only identified renewable energy resource expansion associated with the data center customer was 30 MW of single axis tracking photovoltaic (PV) solar. Actual resource additions will vary from this list as the data center expands and to account for practical limits like transmission system availability for the wind resources.

Energy Storage Technology

Energy storage is the capture of energy produced at one time for use at a later time. Types of energy storage technologies include battery, mechanical storage such as a fly wheel, or thermal storage such as ice storage. Table 24 summarizes several storage technologies. Not only can PNM use energy storage to meet system peak load, it can potentially use it as operating reserves. PNM can also use energy storage to modify load (e.g., by charging the storage system during typically low-load periods such as during the night). Various energy storage technologies are in different phases of development and many are in the demonstration phase.

Table 24. Storage Technologies

Storage Technology	Expected Life	Description	Comments
Compressed Air	15-20 Years	Uses off-peak energy to compress air for storage; suitable geologic space required for large scale	Requires geology with good containment (salt caverns, underground mines, etc.); mature technology
Flywheel	20+ Years	Mechanical devices that spin, storing rotational energy that is released when needed	High power density, relatively low energy capacity (short powerful discharge)
Pumped Hydro	20+ Years	Water lifted off-peak to a reservoir above a conventional hydro power plant	Limited available sites; proven technology
Other	Varies	Includes ice and other thermal storage	
Battery Lead-Acid	5-15 Years	The most common battery; a mature technology, available since the 19th century	Proven workhorse, but in utility application has low depth of discharge, poor operation in partial charge and short lifespan;
Battery Lithium Ion	5-15 Years	Most common battery type for current utility scale storage installations. Used extensively in electronics.	Electric vehicle and utility applications
Battery Sodium	5-15 Years	Classified as high temperature; generally maintained at temperature of 300°C or more	High cost with support system requirements (high temperature)
Battery Zinc	5-15 Years	Zinc batteries have a number of potential advantages, but are not in widespread commercial deployment	Currently unproven at commercial cost level requirements
Flow Battery	15-20 Years	Rechargeable and akin to fuel cells; two chemical solutions allow current to pass thru a separating membrane	Scalable, some concerns with balance of system costs; high potential for future advances

Batteries appear to have best potential for widespread application and provide services such as peaking capacity, time shifting of generation to match load or supply levels, frequency regulation, distribution service quality, transmission support, ramping support, and operating and contingency reserves. The choice of battery type, size and design will affect the ability to provide these various services and the cost. Design factors include battery capacity, total energy storage, rate of recharge, efficiency of energy returned versus charging energy, expected life, degradation of performance (over time, cycles, etc.) and system regulation capability.

Recent public policy actions are improving the cost-effectiveness of battery (or other) storage technologies. The California Public Utilities Commission established a target of installing 1,325 MW of storage capability on the grid by 2020. This mandate should drive future cost savings due to the sheer scale of deployment in California. Core research funding is also ongoing in industry and academia. Tax incentives are available for battery investments that are coupled with renewable energy resources. In light of these measures, PNM expects that battery storage may be cost effective within the plan horizon.

PNM included two versions of battery storage in the capacity expansion modeling: a 2 MW, two-hour storage battery and a 40 MW, four-hour battery. The capital cost of the two-hour battery is assumed to be $1,892/kW and the capital cost for the four-hour battery is assumed to be $2,925/kW. These prices are based on recent battery acquisitions in neighboring service territories and are verified using the EPRI cost database. The reliability analysis will explore the quantity of energy storage required to have a beneficial impact on system reliability, and PNM will estimate the range of costs that can be avoided for provision of spinning reserves if a battery is installed in the system. The capacity provided by a battery is assumed to be capable of meeting the need for traditional quick-start generation capacity that would be provided by an equivalent amount of gas-fired capacity.

Universal Solar PV

PNM has included several universal solar photovoltaic (PV) resource additions—all assume single axis tracking technology. The additions are assumed at three different sizes: 10 MW, 50 MW, and 100 MW. Pricing options shown in the table in Appendix K reflect the revenue requirements calculated from bids received by PNM in a public request for proposals for renewable energy resources issued in 2016. The cost data assumed for the resources also assume solar resources built before 2020 receive the current 30% federal investment tax credit. Beginning in 2020, solar resources will receive a 10% federal investment tax credit; however, for modeling purposes PNM retained the 30% assumption throughout the planning period. Because solar pricing has been changing rapidly, and the cost is dependent upon unknown, future tax credits, PNM performed a sensitivity analysis (See Analysis Results Section, Solar Sensitivity) to determine the impact of a wider range of solar pricing on portfolio recommendations.

PNM also assumed appropriate transmission interconnection costs and transmission upgrade costs for each of the three potential sizes. Finally, the smaller resources are assumed to be interconnected to PNM's distribution system; larger resources require interconnection at the transmission voltage level.

As solar energy production increases on PNM's system, the need for resources to meet peak load after accounting for solar energy's contribution moves to later hours in the day. PNM applied a declining contribution to the reserve margin with each successive solar resource addition.

When PNM evaluates the ability of incremental solar capacity to help meet system peak load, it considers the extent to which previously installed solar will shift the net peak hour. This analysis is described in the Analysis Results Section, Solar Sensitivity

Beyond this decline in the peak contribution from incremental solar, The California Independent System Operator (CAISO or California ISO) has identified other challenges for the electric grid. CAISO depicted this situation in a now famous graph of peak demand less solar resource capacity (in California) that has become known as the duck curve due to its resemblance to the profile of a duck (Figure 19).

> "With a changing resource mix that includes an increasing amount of variable energy resources, the California ISO will face steep ramps and will need to meet increasing or decreasing electricity demand quickly. We will need resources with fast ramping and fast start capabilities as well as the ability to start multiple times during an operating day. The California ISO also expects an increased risk of over-generation, when resources are supplying more electricity than is needed to satisfy real-time electricity requirements. This condition creates negative market prices that may create shortfalls in expected market revenues for certain resources. In addition, there is a risk of decreased frequency response capability when fewer resources are operating and available to automatically adjust electricity production to maintain grid reliability.
>
> "…the reduction in generation capacity that can adjust its production of energy in response to under- or over-frequency occurrences raises grid reliability concerns. The California ISO must maintain resources with sufficient capabilities on its system at all times to effect real-time control performance. In order for ISO to comply with FERC's recently approved Frequency Response and Frequency Bias Setting standard (BAL-003-1), the ISO will have to operate in a manner such that resources on governor control must forego operating at their maximum capability and reserve available headroom at all times in order to provide frequency response following a disturbance. Low net load conditions create more challenges to meet this requirement because it requires the commitment of additional resources at a time when too much generation is already on the system."[5]

PNM analyzed these issues, and the analysis is discussed in the Analysis Results, Reliability Analysis section. At the current level of solar capacity on its system, PNM continues to receive peak capacity benefit from incremental solar and does not yet experience the severe operating challenges of the duck curve situation. However, the Western grid is experiencing higher penetration levels and utilities in the southwest are particularly affected. Solar resources best match loads in utility systems where the peak load occurs during summer daytime hours.

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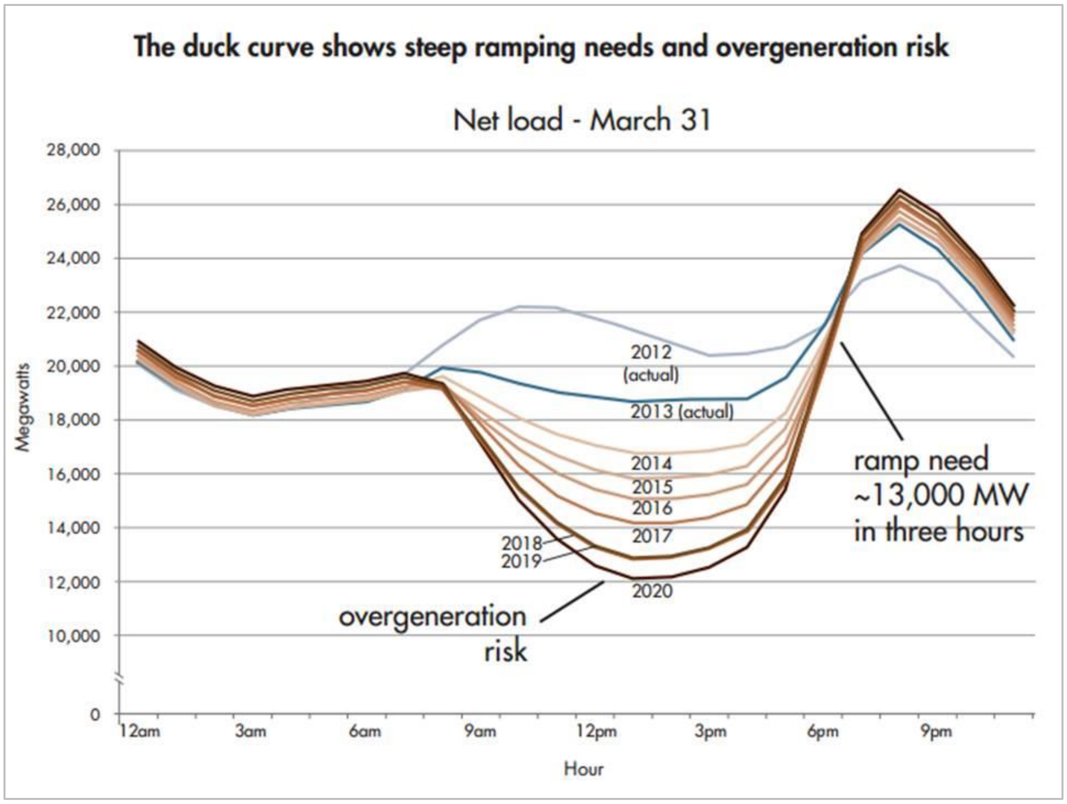
[5] FERC Docket No. AD14-9-000, comments of Brad Bouillon, CAISO

Figure 19. California "Duck Curve"



Solar Power Tower with Storage

Solar thermal facilities concentrate sunlight on a receiver which then transfers the heat to a working fluid that is used in a steam turbine to generate energy. PNM has not received any recent bids for solar thermal resources to provide input assumptions for a new resource. Rather, PNM relied on data from a solar power tower installation to characterize this potential new resource. The revenue requirements in the portfolio analysis are calculated based on a 100 MW solar thermal tower, a 45% capacity factor at an all in energy price of $185 per MWh.

Wind

Wind resources were characterized in generic 50 to 100 MW increments with a 40% capacity factor based on bids received by PNM in a 2016 public request for proposals for renewable energy resources. PNM conducted a sensitivity analysis around wind price, capacity factor, and total capacity that can be integrated into the portfolio. Wind price and availability are also impacted by transmission availability. If transmission system capacity is insufficient to transfer energy to loads, costs must reflect the need for additional transmission.

Small Aeroderivative

A 40 MW aero derivative option was considered with a 9,800-Btu/kWh heat rate and $1,150/kW installed capital cost. This unit can provide quick-start capability (full operating load in 10 minutes) to provide contingency reserves. PNM assumed this resource would not require any major transmission upgrades because it would be sited within WECC Path 48 in north central New Mexico.

Large Aeroderivative

PNM considered a typical 85 MW gas turbine with a 9,800 Btu/kWh heat rate and $1,065/kW installed capital cost. This unit can provide quick-start capability for contingency reserves (full operating load in 10 minutes). PNM used the Electric Power Research Institute's (EPRI's) Technical Assessment Guide (TAG) database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level to represent typical siting conditions around New Mexico. PNM assumed this unit would be sited within WECC Path 48 in north central New Mexico and not require transmission upgrades.

Heavy Frame Combustion Turbine

PNM included an option for the newer more efficient heavy frame 187 MW gas turbines with a 9,600 Btu/kWh heat rate and $753/kW installed capital cost. This technology can help PNM maintain system voltage and regulation and meet spinning reserve requirements. It is expected that these resources will require relatively little acreage and minimal amounts of water. PNM assumed this resource can be sited at SJGS and not require transmission upgrades because of the retirements of SJGS Units 2 and 3 by the end of 2017.

PNM also assumed that one of these units could be sited at or near SJGS and utilize available transmission from the SJGS to PNM load centers in north central New Mexico (see the "Existing Transmission System" section). It was also assumed the cost to build a new gas pipeline from an interstate pipeline to the SJGS plant would be included in the price estimates for the gas transportation agreement with this option.

1x1 New Combined Cycle Gas Generation

Compared to gas peaking resources, combined cycle plants tend to be more expensive to build and less expensive to operate on a per MWh basis. For this option, PNM assumed a 1 x 1 combined cycle gas turbine of a typical 289 MW manufactured size and $1,023/kW installed capital cost and approximately a 6,950 Btu/kWh heat rate. Combined cycle plants require significant amounts of water to condense the steam cycle. To minimize water usage and associated costs, PNM assumed this combined cycle gas turbine will utilize hybrid or dry cooling technology, which is included in the capital cost estimates. PNM used the EPRI TAG database as the source of the unit characteristics and adjusted the TAG data for 5,000 feet above sea level.

Rio Bravo Expansion to 1 x 1 Combined Cycle

There are two existing heavy frame combustion turbines in PNM's resource portfolio that may be retrofit with a heat recovery steam generator and steam turbine to create a new 1 x 1 natural gas combined cycle generator. PNM characterized a conversion of the Rio Bravo facility to model this resource. Expanding Rio Bravo would increase the capacity of this unit from 138 MW on peak to 210 MW (for a total 72 MW increase), while improving the heat rate from 11,071 to 7,200. Converting a combustion turbine to combined cycle would also likely eliminate its quick-start capability. Because combined cycle expansion works on heat recovery from the existing combustion turbine, no additional gas supply is needed. In addition to expected costs to upgrade the unit, PNM assumed a $5 million transmission system upgrade would be required. Because the cost and feasibility of this upgrade is currently unknown, PNM conducted sensitivity analysis around the capital cost requirements.

250 MW Existing Combined Cycle

PNM characterized a resource option to purchase a 250 MW share of a 550 MW existing combined cycle plant. This assumption is based on a similar transaction in Arizona. The capability of this unit is based on a 2 x 1 combined cycle generator with a heat rate of 7,000 and a capital cost of $700/kW, including costs for transmission. This characterization is for modeling purposes because PNM is unaware of any partial purchases of a 550 MW natural gas combined cycle unit.

Reciprocating Engines

PNM included reciprocating engine generators of up to 41 MW in one installation, with a heat rate of 8,800 Btu/kWh and $1,218/kW installed capital cost. These engines are natural gas-fired and have the cost and performance characteristics of peaking resources. Reciprocating engines can operate over the full range of the unit size, offering quick-start generation and maximum load following flexibility. The EPRI TAG database was used as the source of the unit characteristics. PNM assumed this resource would be sited within WECC Path 48 in north central New Mexico and not require transmission upgrades.

Potential Projects to Improve Transmission Capability

Under-Construction Transmission Facilities

PNM's transmission construction plans are derived from its annual transmission planning process. The projects listed below are currently under construction or have been completed recently. These projects are intended to provide additional transmission capability or voltage support to increase or maximize utilization of existing transmission facilities. The projects are primarily addressing capacity constraints associated with load growth and existing transmission service obligations and do not specifically address constraints associated with new, specific resource locations, as listed here:

- **Blackwater Switching Station Expansion** – The Blackwater Station was expanded in association with the interconnection of Western Interconnect. LLC transmission line for the Broadview wind farm (in service January 2017).
- **Clines Corner Switching Station** – new switching station in association with the interconnection of the El Cabo wind farm to the EIP line (in service April 2017)
- **Richmond Switching Station** – new switching station in Albuquerque which allows for reconfiguration of the existing 115 kV lines to mitigate 115 kV overloads (expected to be in service July 2017).
- **Yah-Ta-Hey Transformer Addition** – mitigates overloads and improves voltage performance in western New Mexico (expected to be in service fall 2017).

- **Guadalupe Static Var Compensator (SVC)** – provides voltage support that will enable the full utilization of the B-A to Blackwater transmission line for point to point transmission service (expected to be in service March 2018).
- **Cabezon Switching Station** – new switching station in Sandoval County in association with the interconnection of Tri-State new 345/115 kV Torreon substation to the Cabezon Station on PNM's San Juan-to-Rio Puerco 345-kV transmission line (expected to be in service April 2018).

Potential New Transmission Projects

PNM characterized potential new transmission projects associated with new generation, or for possible energy purchases for analysis in this IRP. The next few sections describe these resources.

New Generation in Southern New Mexico

PNM considered an 80 MW new generation resource to be developed in southern New Mexico. Associated with this potential resource is the need for additional third-party firm point-to-point transmission service from Tucson Electric Power (TEP) to be able to transmit the power to PNM's central and northern load centers. Based on TEP's current FERC-accepted transmission tariff rates, the expected transmission cost for 80 MW plant, including ancillary services, are approximately $2.6 million per year. Additionally, the expected interconnection costs for the 80 MW Plant connecting to the 345 kV transmission system in southern New Mexico is $12 million, assuming a new three breaker 345 kV station connected to a PNM transmission line.

New Generation Near Belen, New Mexico

PNM also considered a new 40 MW plant sited near Belen, New Mexico. La Luz is an existing 40 MW facility but has a transmission interconnection agreement to expand to 80 MW. The transmission system from the Belen area to Albuquerque is at or near its maximum transfer capability. If the facility is expanded beyond 80 MW, or any other new capacity is added near Belen other than a 40 MW expansion at La Luz, a high capacity transformer is needed to replace the Tome 115/46 kV transformer and the line termination switches on the Person-Tome 115 kV line need to be replaced. Assuming, for example an incremental 40 MW incremental generation after La Luz is expanded will require the following transmission upgrades:

- Convert the Person-Belen 46 kV line to operate at 115 kV, including: the 46kV rated equipment at Louden Hills and Bosque Farms distribution stations; expand the Person and Tome 115 kV stations;
- Re-conductor the Person-Prosper 115 kV line to higher rating; and
- Re-conductor the Prosper- KAFB 115 kV line to higher rating.

The cost of these transmission upgrades would be approximately $20.3 million, with an expected interconnect cost to connect to the Belen 115 kV switching station, of $1 million.

New Generation at SJGS Station

A new 80 MW generating plant at the San Juan switching station requires an expansion of the switching station to add a new bay position and all interconnection equipment. In addition, a west bus sectionalizing 345 kV circuit breaker will need to be installed to split the bus to accommodate the long outage construction time for the new bay position. The expected cost of these transmission upgrades is $4.6 million

Potential New Transmission Projects

PNM characterized potential new transmission projects associated with new generation, or for possible energy purchases for analysis in this IRP. The next few sections describe these resources. Building transmission requires a long-term view. Transmission is a classic victim of "not in my back yard" sentiments and transmission is particularly challenging to site given the amount of public and Native American lands in New Mexico.

Merchant Transmission in New Mexico

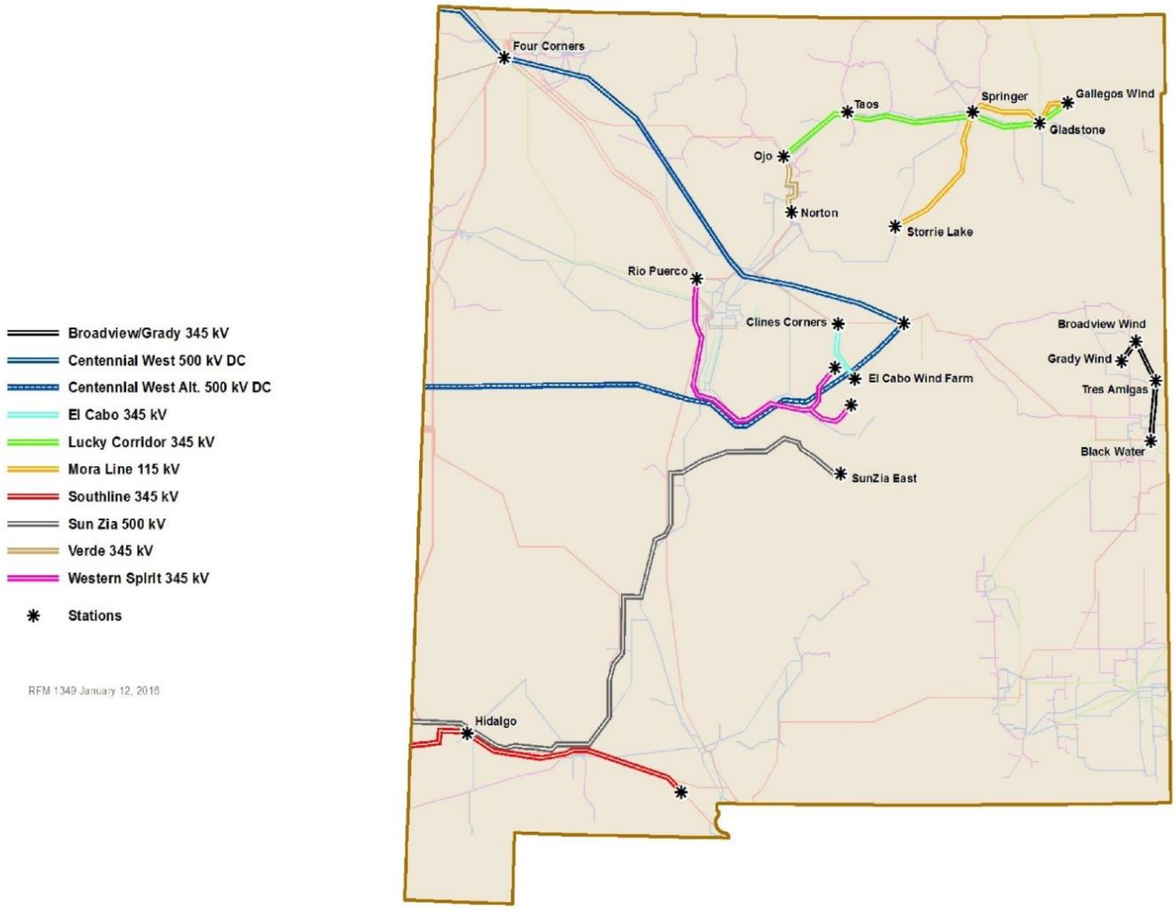
Transmission development, particularly high voltage transmission, is the focus of a number of policy initiatives at the federal and regional levels. Significant transmission is needed throughout the country if the highest quality renewable energy potential is to be developed and transported to load. To meet this need, FERC has developed rules and incentives to enable merchant transmission. As a result, there are a number of merchant transmission project proposed in New Mexico as shown in Figure 20. Some of these merchant projects could take 10 or more years to complete and several of these are projected to cost $1 billion or more.

PNM is required, per FERC policy, to provide transmission interconnection service on a non-discriminatory basis to any eligible customer that submits the requisite application and information. Once a valid application for transmission interconnection is submitted, the procedures provide for a study process that determines the most appropriate facilities necessary to interconnect the proposed transmission project to the transmission grid. The study process also determines the impacts to the transmission grid caused by the proposed interconnection and any transmission system reinforcements needed to remedy such impacts, if required.

PNM has completed technical studies and executed a Standard Transmission Construction and Interconnection Agreement in July 2012, which incorporates the requirements for interconnection of the Tres Amigas 345 kV line (Western Interconnect) to PNM's Blackwater station. The Tres Amigas interconnection to PNM's Blackwater Station was completed in January 2017 to inject power from the Broadview windfarm. The El Cabo 345 kV transmission line interconnection is being developed by Avangrid for their El Cabo wind farm (298 MW) that will interconnect to PNM's EIP line near Clines Corners by April 2017 as part of a large generation interconnection agreement.

PNM is in process of completing the technical studies for the Mora 115 kV line, Western Spirt 345 kV line and Verde 345 kV line transmission interconnection projects. Figure 20 shows the proposed location of each of these lines.

Figure 20. Potential New Merchant Transmission



The Mora 115 kV line is proposed by Lucky Corridor, LLC and could interconnect with PNM's and Tri-State Generation and Transmission Cooperative's 115 kV systems in northern New Mexico. The project would serve to connect approximately 160 MW of renewable resources in north eastern New Mexico. The project would potentially support delivery of additional renewable resources to the Four Corners area or load in north eastern New Mexico.

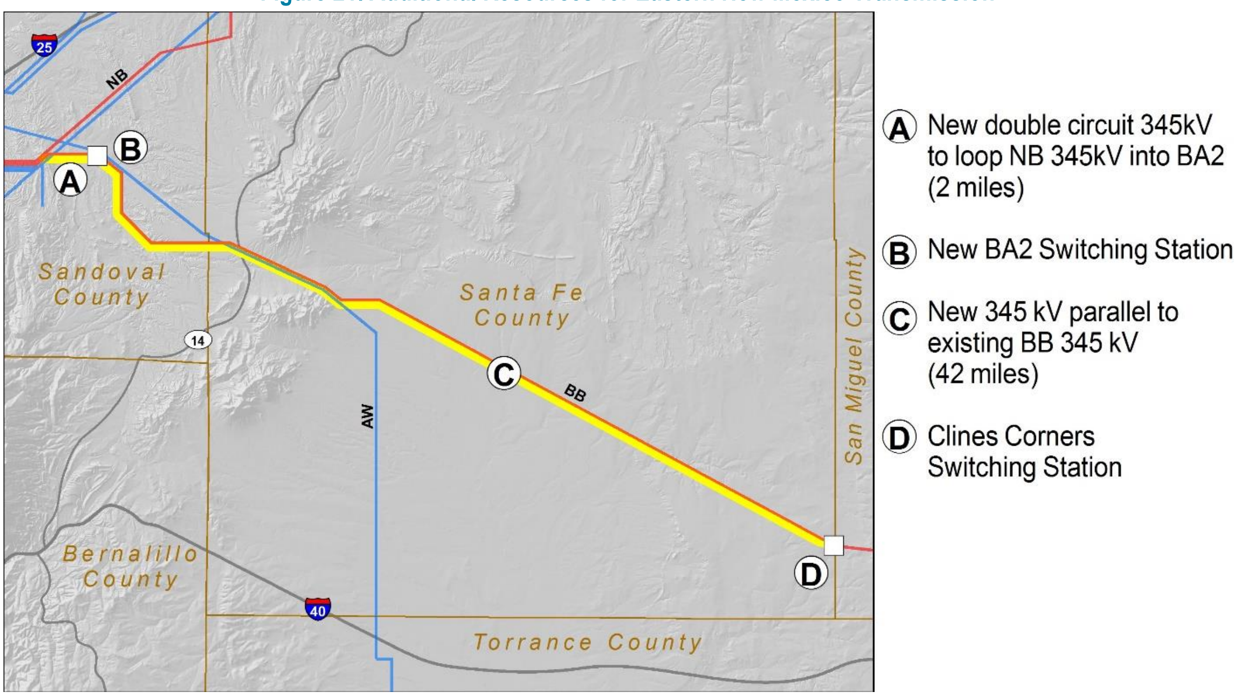
Development of the Western Spirit project is being pursued by Clean Line Energy Partners. The project consists of an approximately 140 mile 345 kV line that could deliver up to 1000 MW of renewable energy resources from east central New Mexico to PNM's Rio Puerco switching station. The project would enhance the ability to deliver additional renewable resources to loads in northern New Mexico or for export to the Four Corners area and out-of-state markets.

The Verde transmission line, proposed by Hunt Power, connects the Ojo 345 kV switching station to the Norton 345 kV switching station through an approximately 30 mile 345 kV line. The project would increase the ability to import power into Northern New Mexico from the Four Corners area by completing a third full 345 kV path into the Albuquerque metropolitan area. Along with other system improvements, the Verde project would be expected to accommodate the import of between 400 to 650 MW of additional resources located at San Juan, Four Corners or in Arizona. The project also has the potential to support exports of wind generation to the Four Corners area from eastern New Mexico if additional delivery capability into the existing transmission system around Albuquerque is developed.

Eastern New Mexico Transmission

The New Mexico wind resources are concentrated in the eastern portion of the state. The existing and development of wind farms in the area will result in 1000 MW of transmission service obligations on the EIP line. Any additional transmission service commitments will require that additional transmission lines and stations be developed. There is presently a desire for additional firm transmission capacity from eastern New Mexico to accommodate renewable energy development by wind merchant developers. Additional transmission capacity above 1000 MW can be achieved by building a parallel transmission line, 345 kV circuit, between the Clines Corners 345 kV station and a new 345 kV station east of the existing BA station (looping in the existing BB line and the BA-Norton line). Building these facilities will result in additional 300 to 400 MW of firm capacity from the Clines Corners area. Figure 21 illustrates the additional resources considered.

Figure 21. Additional Resources for Eastern New Mexico Transmission



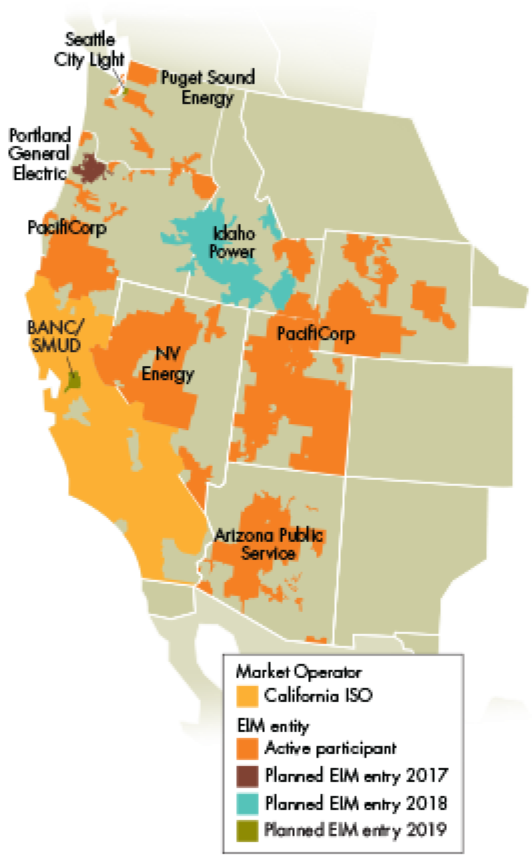
Potential New Electric Market Interactions

CAISO Energy Imbalance Market

The California Independent System Operator (CAISO) has developed an Energy Imbalance Market (EIM) to help California solve some of the issues caused by the increasing amounts of variable energy resources. CAISO's Energy Management System (EMS) receives real-time operational data from participants and produces dispatch simulations to optimize near term future electricity supplies to meet demands over the EIM footprint while accounting for transmission and other system limitations. Dispatch instructions are sent to the BAs for participating resources and the BAs are expected to dispatch their generation to comply with the instructions from CAISO or otherwise face penalties.

CAISO launched the western Energy Imbalance Market ("EIM") on Nov. 1, 2014 with its first utility participant, Oregon-based PacifiCorp. EIM was later joined by Las Vegas-based NV Energy on Dec. 1, 2015, Puget Sound Energy of Bellevue, Washington, and Arizona Public Service of Phoenix, Arizona, on Oct. 1, 2016. This voluntary market service is available to other utilities in the West. Portland General Electric and Idaho Power each announced they will be EIM participants. Figure 22 illustrates the utilities currently in and committed to join the EIM.

Figure 22. EIM Participants



The EIM aggregates the variability of electricity generation and load for multiple balancing authority areas and utility territories and performs a five-minute security constrained economic dispatch. In addition, an EIM facilitates greater integration of renewable resources through the aggregation of flexible resources from neighboring states, capturing the associated diversity benefits from the expanded geographic footprint and the expanded potential use for those resources.

The EIM operating rules require each BA area to maintain enough generation capacity to meet load, ramping and reserve requirements and prohibit reliance on other market participants for reliability and capacity. EIM allows the BA to use less expensive third-party generation when sufficient real-time transmission is available to replace more expensive generation resources, but it is not a means by which utilities can reduce or avoid system reliability requirements.

Participation in the EIM is open to BAs in the WECC meeting specific requirements. To participate, PNM would be required to upgrade certain meters and other hardware to comply with data accuracy and reporting requirements in addition to upgrading its software to be able to manage the additional complexity of operating in an EIM environment. Additional accounting and operations personnel would likely be needed as well. In return, PNM could save energy costs by sharing in the higher operational efficiency of the EIM and reducing regulating requirements for its own variable energy resources. PNM plans to study the costs and benefits of joining the EIM in the future.

Table 25 shows the startup and ongoing cost for PacifiCorp, Nevada Energy, Arizona Public Service, and Puget Sound Energy. The utilities that have joined the EIM so far have had a favorable outcome with respect to payback time of the initial investment. Nevada Energy and Arizona Public Service currently have staff of 10 and 14 FTEs, respectively to administer EIM (e.g. real-time desk, resource scheduling, outage tracking, energy accounting).

Table 25. EIM Startup and Ongoing Costs and Projected Benefits

Utility	Start	Estimated Customers	Estimated Generation Capacity (MW)	Startup Costs	Ongoing Costs	Gross Benefit Estimate (Company Only)
PacifiCorp	1/1/2014	1,700,000	10,600	\$3M - \$6M	\$2M - \$5M	\$21M - \$129M 2017 in 2012\$
Nevada Energy	1/1/2015	1,200,000	6,100	\$11M	\$2.6M	\$9M - \$18M 2017 in 2013\$ and \$15M - \$29M 2022 in 2013\$
Arizona Public Service	10/1/2016	1,200,000	9,000	\$13M-\$19M revised to \$23.5M	\$4M	\$7M-\$18M 2020 in 2014\$
Puget Sound Energy	10/1/2016	1,100,000	3,000	\$14.2M	\$3.5M	\$18.3M-\$20.1M 2020 in 2014\$

PNM plans to contract with a consulting firm to perform a study to evaluate the costs and benefits of PNM participating in the EIM. The study will evaluate EIM benefits to PNM based on a set of study scenarios, including loads, resources, and potential transmission constraints for access to markets for real-time transactions.

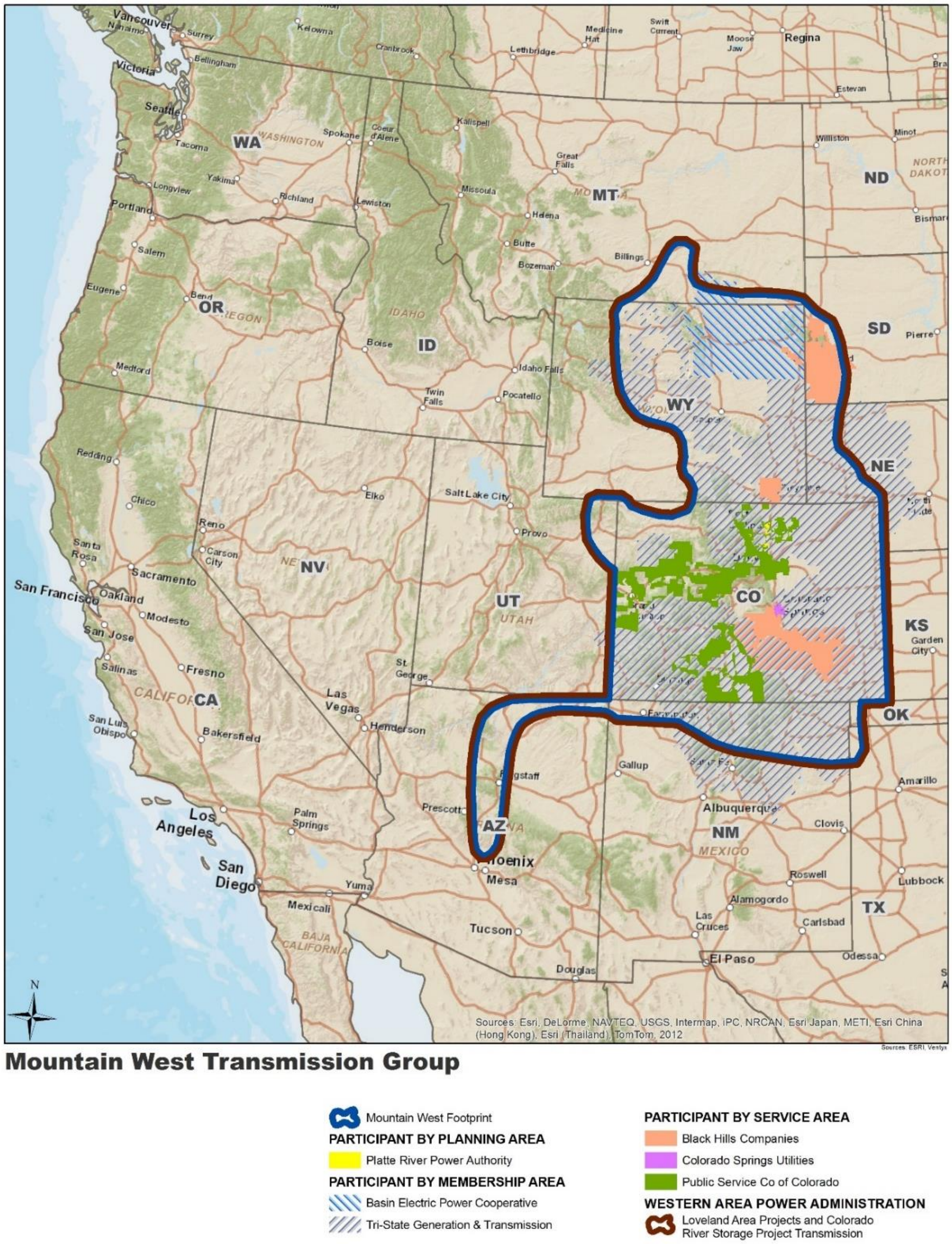
Mountain West Transmission Group

An effort to create an organized electricity market is taking shape in the inland West even as CAISO continues to build the case for expanding its operations into the wider region. A number of other Colorado utilities have become more involved in the development of the Mountain West Transmission Group ("MWTG"). The MWTG is analyzing the possibility of developing a single transmission tariff and provider throughout Colorado and the WAPA system in Arizona. All the parties in the following list would potentially be a network customer of MWTG:

- Public Service Company of Colorado (PSCo)
- Western Area Power Administration (WAPA)
- Tri-State
- Basin Electric
- Black Hills Corp
- Platte River Power Authority
- Colorado Springs Utilities

As shown in Figure 23, the group's footprint covers most of Colorado and Wyoming, along with smaller areas of Arizona, Montana, New Mexico and Utah.

Figure 23. Footprint of Proposed Mountain West Transmission Group



The MWTG issued a request for information (RFI) from Reginal Transmission Organizations (RTOs) to CAISO, SPP, Mid-Continent Independent System Operator (MISO), PJM Interconnection (PJM) to provide tariff administration services and market operator services. MWTG is also performing a market study to assess organized market benefits.

The Mountain West Transmission Group is currently evaluating different options for its members that include forming their own Regional Transmission Organization (RTO). Although PNM is not a member of Mountain West, other nearby utilities are and, therefore, availability and/or costs of power at the Four Corners hub could be impacted.

Potential New Electric Market Interactions

PNM regularly conducts wholesale power transactions to help balance electric supply and demand and to help keep fuel costs low. The transactions are between PNM and other utilities and market participants in the WECC, and serve to increase the overall efficiency and cost-effectiveness of the entire electric grid. For example, PNM may purchase energy to meet a shortfall in total available generation for the next hour at a lower cost than starting one of its own gas-fired peaking units. Or, if PNM has extra capacity for the next hour and other market participants are offering to purchase at prices that are higher than the incremental costs of generating the additional energy, PNM will sell its excess. The less expensive purchased energy and the revenues from sales are credited to PNM’s customers via the fuel clause.

Power is frequently traded at locations where multiple entities have transmission and generation such as the Palo Verde or Four Corners hub. Power for future delivery can be bought or sold in multiple time frames, but can generally be categorized as “month(s) ahead,” “day(s) ahead,” and “hour(s) ahead.” Intra-hour transactions are typically not available to PNM, so PNM must utilize its own generation to regulate for unpredicted changes in renewable generation or load within the hour. Month-ahead and day-ahead transactions are generally traded in a quantity of power for certain blocks of hours called “on peak” and “off peak.”

PNM’s opportunities to buy and sell power have declined over the past few years because of various reasons such as baseload unit retirements in the region, entry into the California EIM by certain entities, more stringent electricity and gas scheduling requirements, FERC rules requiring designation and undesignation of resources, scheduling and tagging constraints, and transmission availability/costs from trading hubs that have more participants. The decline in available market liquidity requires PNM to rely on its own resources to balance supply and demand more often in the future than in the past.

ANALYSIS TECHNIQUES

ANALYSIS TECHNIQUES

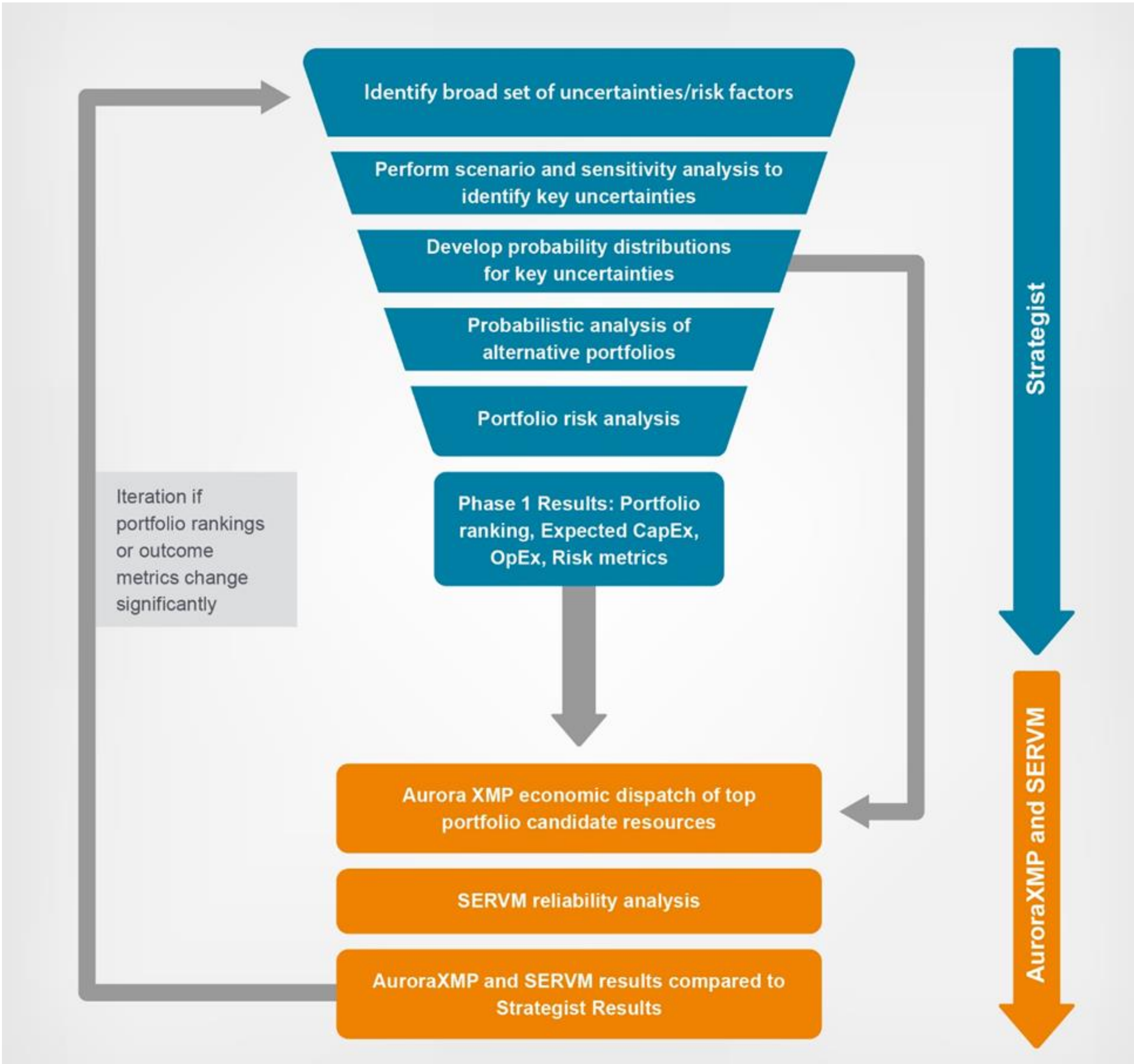
The analytical goals of the IRP are to develop an MCEP and a four year action plan to pursue the MCEP, along with the other beneficial strategies identified. The IRP Rule defines MCEP as "those supply-side resources and demand-side resources that minimize the net present value of revenue requirements proposed by the utility to meet electric system demand during the planning period consistent with reliability and risk considerations."

In addition, the MCEP must comply with all legal and regulatory requirements including energy efficiency and demand response program requirements, the RPS and renewable resource diversity requirements, Reasonable Cost Threshold impacts, environmental regulations, transmission system operational requirements, and industry system reliability and operating reserve requirements.

Consistent with IRP best practices, PNM uses several analysis techniques to understand opportunities and risks associated with future uncertainty. The approach combines scenario, sensitivity, and probabilistic analyses to estimate expected portfolio performance and costs, and the associated risks. Scenarios are a set of assumptions defining an overall outlook of the forecast period. In the sensitivity analysis, PNM examines changes to the values of one or more of the assumption input factors within a scenario. For the probability assessment, PNM looks at the impact of simultaneous variation in select input factor values.

This work requires evaluating hundreds of thousands of combinations of demand and supply options in simulations of the complex electric supply grid. Figure 24 describes the process PNM followed to analyze potential resource plans.

Figure 24. Analysis Process

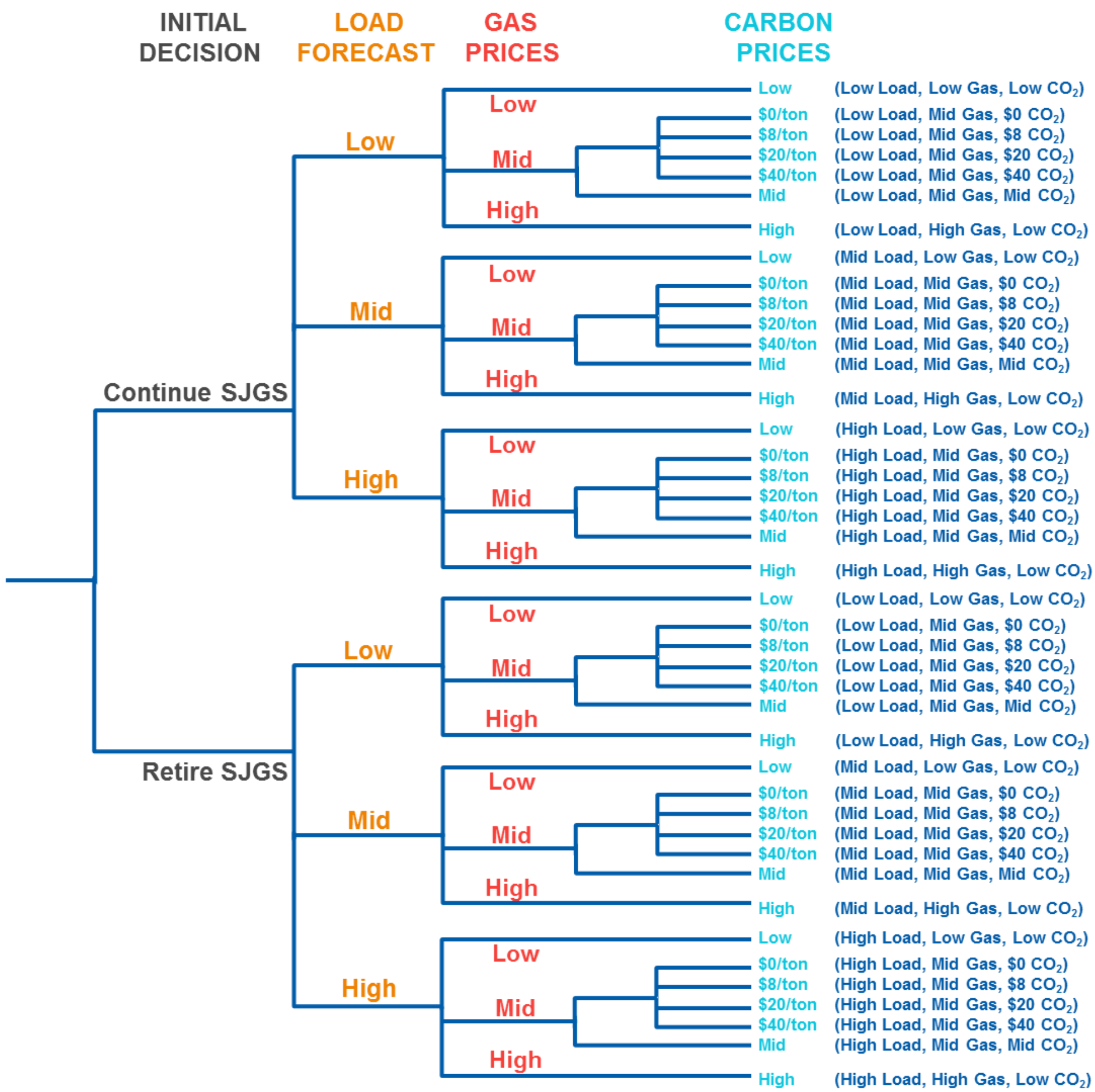


Scenarios

A scenario is an assumed series of events that could affect the selection of the best supply and demand options that PNM should pursue for the MCEP. PNM agreed to develop two primary scenarios in this IRP: a scenario that assumes SJGS will continue operations after 2022, and a scenario that assumes SJGS will not operate after 2022 (soon after SJGS's current coal supply agreement expires). In addition to these SJGS scenarios, PNM defined other scenarios to fully understand the opportunities and risks associated with either SJGS future.

Historically, the assumption with the largest impact on resource portfolio development is the forecasted load. Electric load grows in unpredictable ways and is tied to economic growth in the service territory and changes in electricity use per customer. Additionally, assumptions about future natural gas prices can vary widely and, thus, are used to define scenarios. The historical price volatility and natural gas' prominent role in setting electric prices by fueling the marginal resource that ramps up or down with varying loads at each hour of the day, cause natural gas price assumptions to be an important driver of resource plan decisions. Best practices also dictate that future costs associated with carbon emissions must be considered. Since fossil fuel generation is a significant contributor to the electric supply mix, and anticipated, uncertain future regulation of carbon emissions associated with electricity generation is expected to impact costs, future assumptions for carbon costs are considered in the scenarios. PNM developed 21 scenarios for each of the two primary scenarios around SJGS, for a total of 42 primary scenarios. The primary scenarios are further analyzed through sensitivity analysis described in the Sensitivity Analysis section. The primary scenarios are identified and numbered sequentially in Figure 25.

Figure 25. Primary IRP Scenarios



SJGS Scenario Assumptions

Constructing the two primary scenarios required building assumptions around the cost and operation of SJGS before and after 2022. Table 26 summarizes the assumptions used for each of the two primary scenarios.

Table 26. SJGS Scenario Assumptions

Assumption	SJGS Continues	SJGS Retires in 2022
Co-owners	PNM and the other owners will maintain existing ownership shares in Units 1 and 4[6]	The existing operation agreements will define cost allocations for mine reclamation and plant decommissioning
Coal Supply	Existing reserves provide sufficient coal for a new supply agreement through at least 2036	PNM will continue to operate through the 2022 summer peak by managing coal inventory obtained through the current supply contract that terminates on June 30, 2022
Coal Price	Future coal cost sensitivity developed by assumed costs to operate the existing underground mine	Projection of price from the existing coal supply agreement, assuming inventory management to run thorough 2022 summer peak
Ongoing Maintenance	Maintenance cycles and costs are projected based on current budgets for both units	In anticipation of shutdown in 2022, plant management reduces maintenance costs beginning in 2018
Undepreciated Assets	Plant balances will depreciate through 2053	A regulatory asset for unrecovered costs, including return on and return of rate base, will be created and collected over a 20-year period beginning upon retirement

These assumptions were used to create the projected annual costs for operation, maintenance, and fuel cost for the plant under both scenarios.

Load Forecast Scenario Assumptions

The load forecast section of this report provides a detailed explanation of the development of assumptions for three load scenarios for this IRP.

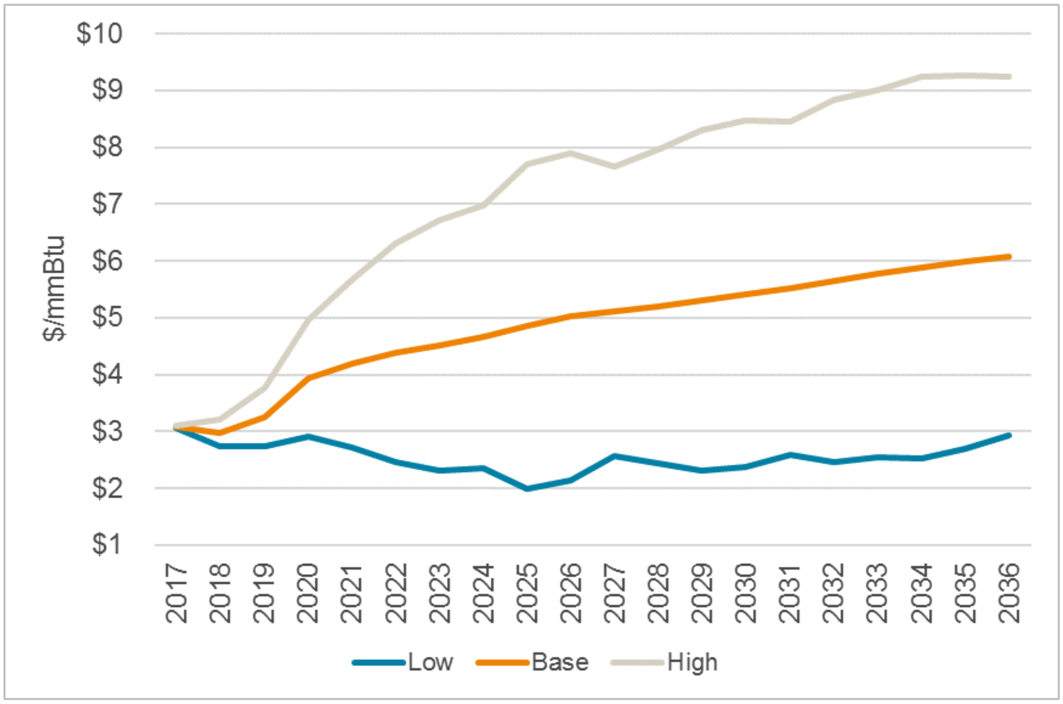
Natural Gas and CO2 Scenario Assumptions

PNM contracted with a nationally known energy consulting service, PACE Global (PACE), to provide a coordinated set of price curves for natural gas fuel and CO_2 emissions for the scenario definitions. PACE created the scenario prices in August 2016 using global natural gas supply and demand, electric supply, and carbon pricing models it had developed to advise previous clients. PACE provided a baseline scenario that assumed a business-as-usual perspective in the short term, followed by an assumption that most states would comply with the stayed CPP

[6] While this IRP uses the assumption that all co-owners would retain their respective shares in SJGS Units 1 and 4 under the SJGS Continues scenario, on April 1, 2017 TEP issued its most recent Integrated Resource Plan. The TEP IRP indicates the utility's intention to exit SJGS upon expiration of the current operating agreements in 2022.

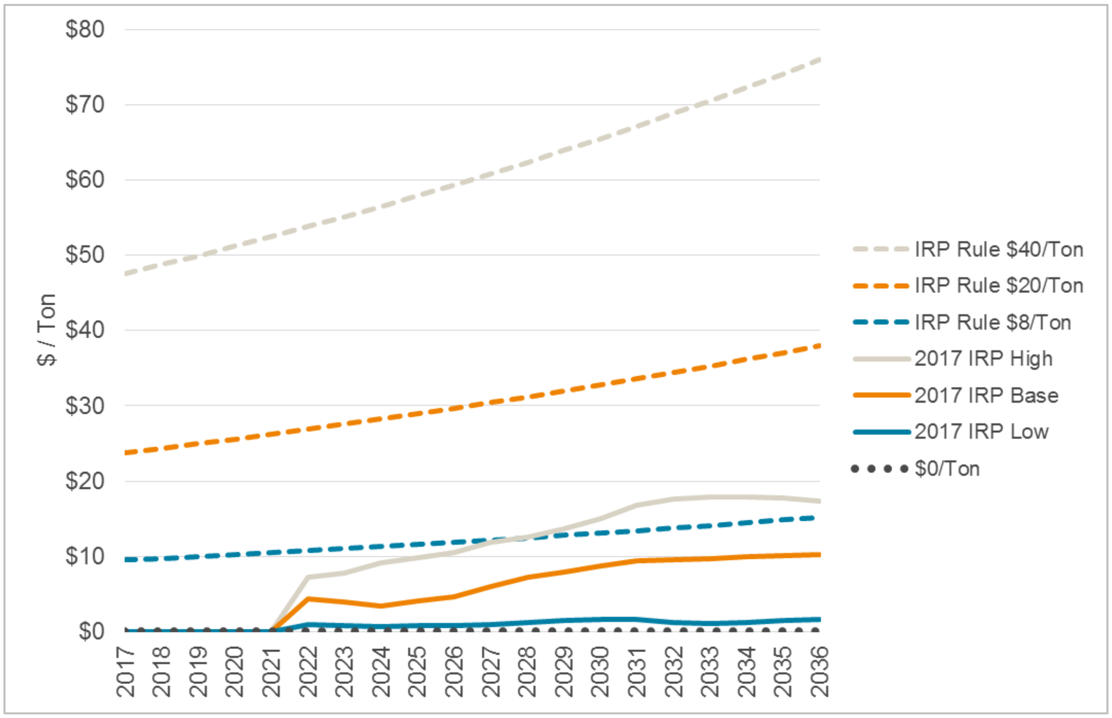
using a mass-based emission standard and interstate trading of allowances. The baseline also assumed that gas and electricity supply and demand would balance over the long term, in line with existing trends. High and low gas as well as carbon scenarios were created using statistical techniques to estimate future CO_2 and gas price ranges. Appendix I provides details of this work. Figure 26 shows natural gas prices in the three scenarios.

Figure 26. New Mexico Natural Gas Price Sensitivities



In addition to the above scenarios, PNM built scenarios using CO_2 price assumptions that were used in its previous IRPs. The final order in NMPRC Case No. 06-00448-UT requires regulated utilities to provide portfolio cost estimates using CO_2 emission prices of $8, $20, and $40 per metric ton (starting price in 2010 dollars, escalating at 2.5% per annum). Also, in response to public advisory comments in previous IRPs, and in recognition of the current uncertainty surrounding future carbon emission regulation, PNM created scenarios that assumed no additional costs would be associated with CO_2 emissions before 2036. Figure 27 illustrates the seven CO_2 prices PNM used for scenario definitions in this IRP.

Figure 27. CO_2 Price Scenarios



Sensitivity Analysis

Resource options or other assumptions can affect the cost and reliability expectation for portfolios within each scenario. PNM tested the impact of the each of the individual assumptions described in the following sections on the mid-load, mid gas price, and mid carbon price scenarios for both SJGS scenarios unless otherwise noted.

Four Corners Power Plant (FCPP) 2031 Retirement

Currently, the FCPP has a coal supply agreement to provide fuel through July 6, 2031 and a site lease that runs through 2041. The base scenarios assume the plant would operate through the end of the existing site lease and assumed that the fuel supply agreement would be extended beyond 2031, past the end of the 2036 planning period. To test the impact of a retirement at FCPP at the end of the fuel supply agreement, PNM analyzed the plan with and without a retirement at FCPP. PNM is currently depreciating FCPP through 2041, so a 2031 retirement analysis includes the assumption that PNM will recover the return on and return of any undepreciated asset value, beginning at plant retirement.

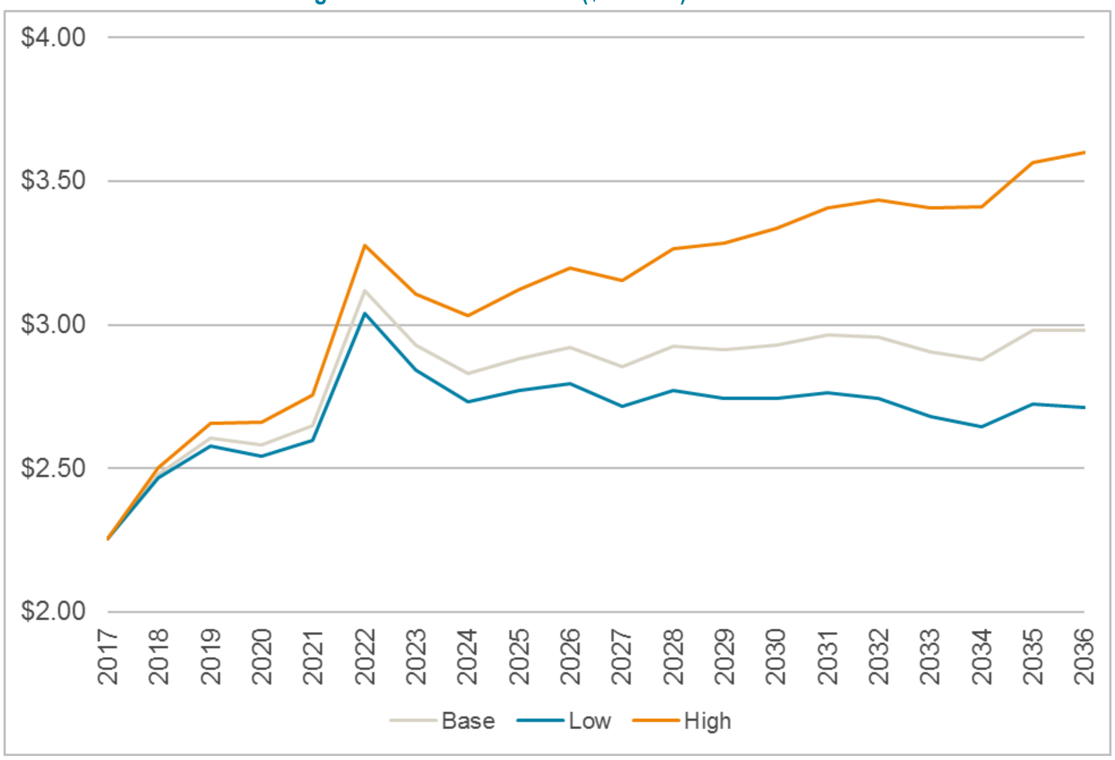
PVNGS-Leased Capacity

PNM conducted sensitivity analysis around whether or not the PVNGS-leased capacity of 104 MW currently projected to expire in 2023 and 10 MW currently projected to expire in 2024 is renewed for future years. PNM also examined the reliability, the cost variability, and the carbon emission impacts of retaining the currently leased capacity. PNM has been investing in leasehold improvements since the plant was built. Whether or not PVNGS-leased capacity is renewed, the costs for PNM to fully recover the costs and return on investment associated with leasehold improvements are included in the plan costs. The cost to secure the leased capacity for long-term use is unknown. If PNM does not use the energy and capacity from the PVNGS leases, the impacts on the portfolios for each scenario also include risks of increased CO_2 emissions, additional natural gas price risk, and the need to pursue resource options to replace the capacity. These risks are discussed in more detail in the Monte Carlo analysis section of this report.

SJGS Coal Prices

PNM estimated coal costs for SJGS for each of the two primary scenarios. Plant management will not determine final coal pricing for 2023 and beyond until July 2018. PNM performed sensitivity analysis using the range of potential coal costs for SJGS to assess the impact of coal prices on the two SJGS scenarios. Coal prices also affect the SJGS Retires scenario due to the impacts of the remaining coal inventory. Figure 28 illustrates the range used for SJGS coal costs.

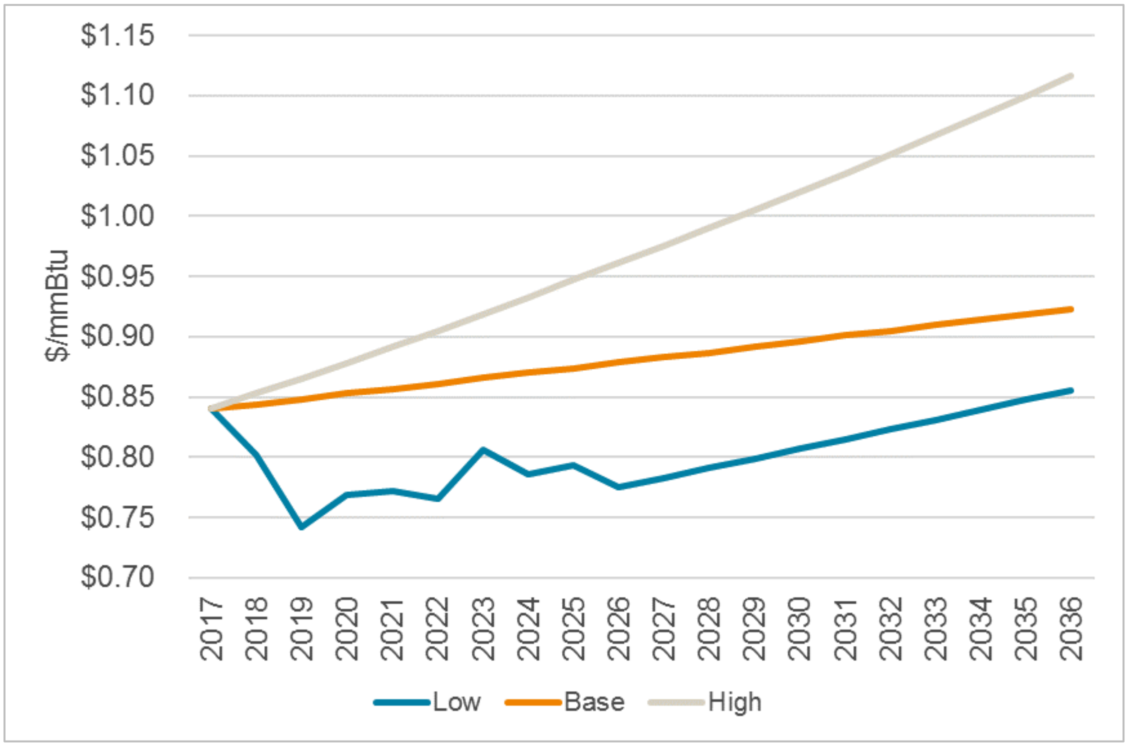
Figure 28. SJGS Coal Price ($/MMBtu) Sensitivities



PVNGS O&M and Fuel Price Range

PVNGS is a significant supply resource in PNM's portfolio. PNM tested the impact of retaining the existing leased capacity on its resource portfolio. In the mid-load scenarios, PNM tested the impact of a range of operations and maintenance costs and nuclear fuel prices as shown in Figure 29.

Figure 29. PVNGS Nuclear Fuel Price ($/MMBtu) Sensitivities



Impact of Energy Efficiency and Demand Response Programs

PNM assumes it will fully spend up to the limit of 3% of revenues on energy efficiency and demand management programs in future years, as required by the EUEA. Sensitivity analysis was conducted to assess the impacts of continuing to implement demand and energy savings associated with the 3% spending level. To perform the sensitivity, PNM removed the incremental demand and energy savings that will be created by future programs to identify the future benefits in terms of overall cost savings and deferring the need to build new generation capacity. Figure 30 and Figure 31 illustrate the incremental and cumulative demand and energy expected from PNM’s energy efficiency programs.

Figure 30. Incremental Cumulative Energy Efficiency Forecast – Demand (MW)

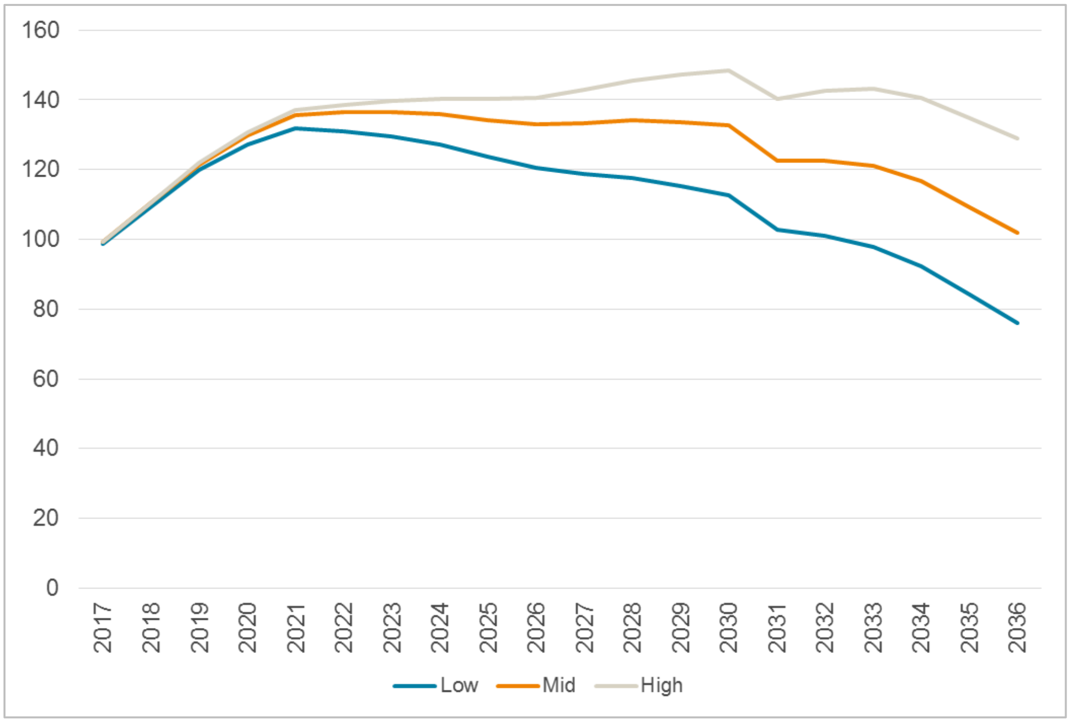
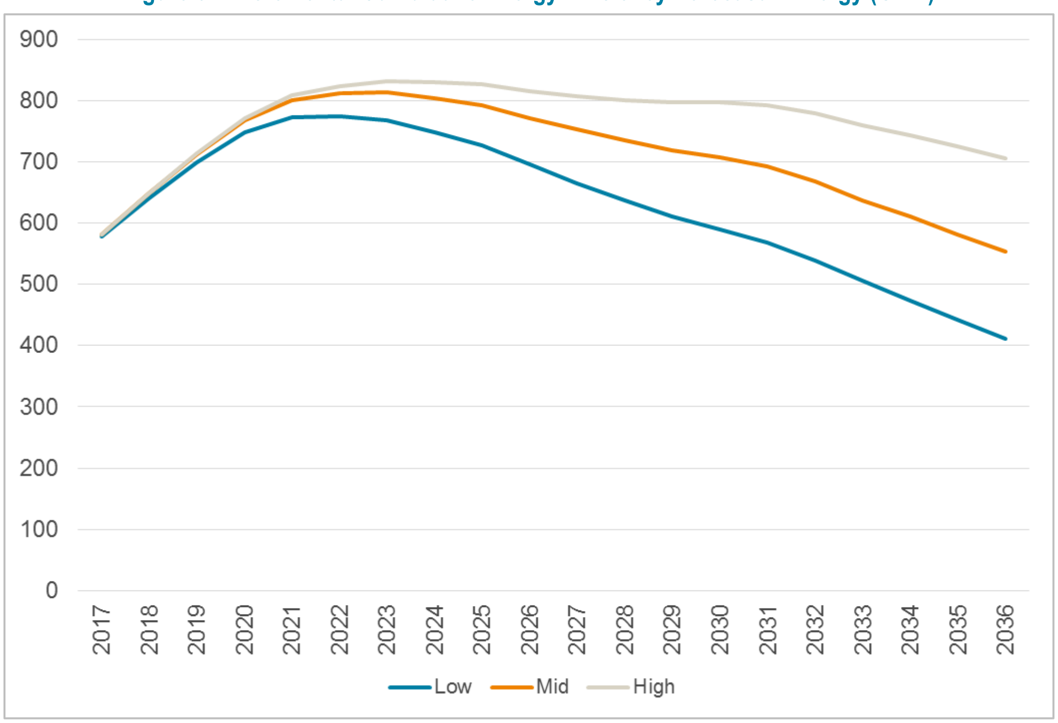


Figure 31. Incremental Cumulative Energy Efficiency Forecast – Energy (GWh)



Natural Gas Type, Size and Price

In the supply option resource database, sizes and prices for a range of natural gas combined cycle plants and reciprocating engine installations were assumed. As of today, PNM does not know what combined cycle options or reciprocating engine options may be provided by the bidders in the request for proposals that will be issued after this IRP. To better characterize the risks and opportunities associated with additional natural gas capacity with lower heat rates than provided by combustion turbines in PNM's resource portfolio, PNM tested a range of purchase prices for natural gas capacity.

Solar Sensitivity

Solar resources were identified as significant resource additions in PNM's 2014 IRP. Going forward, and particularly in the SJGS retirement scenarios, PNM expects a significant expansion of solar resources. Future solar costs are dependent upon tax credits and equipment pricing. PNM has successfully pursued a strategy of adding universal solar in roughly 10 MW increments and interconnected these resources at distribution level, saving money by avoiding interconnection at the transmission level. As the inventory of sites where solar can be interconnected to the distribution system is filled, PNM may need to pursue solar facilities in larger increments, requiring interconnection at the transmission level. PNM has also examined the diminishing return of capacity value associated with solar resources as solar production is added to the system. PNM examined the portfolio costs in a sensitivity analysis to see if additional capacity is needed to meet loads after accounting for solar production late in the day or after sundown. PNM conducted a robust solar sensitivity to understand how future solar additions affect the top ranked portfolios.

Wind Sensitivity

Similar to solar resources, wind costs are dependent upon tax credits and equipment pricing. Wind resources are also sensitive to location (for available wind), and the portfolio impact is affected by the location diversity. Reliability is improved if wind resources are sited geographically distant from each other. PNM conducted a wind resource sensitivity to characterize the risks and opportunities associated with adding wind resources to:

- Evaluate a range of pricing for new wind resources
- Evaluate a range of capacity factors for new wind resources
- Evaluate a range of facility sizes for new wind resources
- Ascertain the value of building new transmission resources to access wind supplies that are geographically diverse compared to PNM's existing wind resources

Renewable Energy Integration Costs

Adding variable types of energy resources (such as wind and solar) requires system flexibility to respond when supply changes quickly or unexpectedly. This takes the form of more frequent starts or ramps at the natural gas generators or operating the natural gas generators at less than full output that is usually associated with higher heat rates. The top ranked portfolio analysis is conducted based on average output characteristics of the resource portfolio. Integration costs are included in the analysis based on study work performed by Astrape

Consulting for the Renewable Integration Study (RIS). In this IRP, PNM used the RIS results to estimate a proxy for integration costs of $1.73/MWh (2018) for solar and from $4.00/MWh (2018) for wind. PNM applied these costs to any new solar or wind resource that the model added to the resource plant to see if there were any changes to the MCEP when these costs were added.

Energy Storage Costs

Utility installation of energy storage resources has become more common. As utilization of these resources increases, the expectation is that costs will decrease as standardization and capabilities improve. Energy storage modeling assumptions were created from public information. To test the impact of a lower future cost on resource portfolios, PNM assumed a declining cost curve based on the historical solar resource price declining rate.

Small Modular Nuclear Reactors

Small modular nuclear reactors (SMR) are potential future resources that can offer a new source of carbon free power, should they become commercially available. The benefits are similar to retaining the PVNGS-leased capacity. There are a few efforts underway to develop this resource, but the precise date of its availability and the future cost is unknown. PNM included an SMR as potential future resource options and tested the sensitivity to price in the scenarios that show significant additions of new energy supplies in the future.

High-Load Forecast Data Center Assumption

As described in the load forecast section, PNM used a range of assumptions for the existing data center in its three load forecast scenarios. To test the impact of adding another data center that is supplied by additional renewable resources which are earmarked to that customer, as often occurs with these types of customers, PNM performed a sensitivity in the high-load scenarios of doubling the renewable energy assumed for the existing data center.

Monte Carlo Analysis

The IRP Rule calls for utilities to consider risk and uncertainty of resource options. PNM conducted scenario and sensitivity analysis to provide a framework for assessing cost impacts of different future assumptions. Real-world system conditions will vary from assumptions and variations of multiple assumptions may occur simultaneously. PNM considered this likelihood using stochastic financial risk analysis (stochastic analysis or risk analysis) to simultaneously vary multiple modeling assumptions and quantify the impact on the total cost of potential resource portfolios. Consistent with IRP best practices, PNM used a specific stochastic financial risk analysis technique known as Monte Carlo to estimate the range of financial risk associated with each portfolio with varying assumptions.

The Monte Carlo simulation uses randomly selected values from variable probability distributions to determine how random variation subject to probabilistic occurrence (stochastic outcomes) affects the cost of the portfolio being modeled. PNM conducted the Monte Carlo analysis using the following steps:

- **Step 1:** Identify the variables that should be included in the Monte Carlo analysis. This was accomplished by inspecting the tornado diagrams resulting from sensitivity analyses to identify those having significant impacts on the portfolio costs.
- **Step 2:** Determine the potential range of values for input variables (including load forecast, natural gas fuel prices, market prices for electricity, and CO_2 costs). Then define a probability distribution for each variable (i.e., the likelihood that each value in the range may occur).
- **Step 3:** Determine the correlation among input variables, if any (i.e., the change in one variable directly related to a change in another variable).
- **Step 4:** Generate a set of random input conditions, one value from each of the defined variables probability distribution reflecting any correlation among the variables, for each year of the study period.
- **Step 5:** Calculate the resource portfolio's total system cost for each selected set of randomly generated variable values using both the Strategist and AuroraXMP models to optimize dispatch of the selected portfolio of resources and then by running the model over 900 draws.
- **Step 6:** Aggregate the results of the random draws from Step 4 and calculate the average net present value (NPV) cost of all the simulations along with the cost of scenario at the 95th percentile of the 900 simulations (representing a 5% likelihood that actual costs are greater than this value).

Reliability Analysis

In addition to the financial risks, PNM evaluated portfolio combinations under various resource scenarios for performance against the reliability metrics of planning reserve margin and loss of load probability. Within the loss of load probability analysis, PNM evaluated whether the risk of loss of load was due to an overall capacity shortage or the need for quick response resources or operating reserves. PNM used this analysis to ensure the portfolio reliably meets demand.

MCEP Evaluation Process

To identify the MCEP for the period 2017 through 2036, PNM examined hundreds of thousands of potential resource portfolios that accounted for multiple scenarios and sensitivity studies of differing resources, economic conditions, carbon prices, and customer demands. Scenarios combining alternative futures for loads, natural gas prices and possible carbon taxes were considered to test the sensitivity of resource portfolio to alternative assumptions and conditions. PNM presented significant results from these studies to the Public Advisory Group during several meetings.

The first step to determine the MCEP is to estimate a top ranked portfolio for each scenario. Differences in the input assumptions between scenarios can result in a different resource portfolio mix. For example, a high gas price scenario will result in a recommended portfolio that has less reliance on gas-fired plants than the portfolio recommended for a low gas price scenario. Sensitivity analysis shows how robust the portfolio choices are within reasonable ranges of input assumptions. Monte Carlo analysis highlights the financial risk associated with a portfolio in an uncertain future. The portfolios is compared against flexibility and other required reliability characteristics. PNM compared the Monte Carlo results under a range of energy demand, gas prices and carbon prices to identify risk mitigation strategies and confirm the importance of individual resource types within the MCEP.

Computational Resources

Several computational resources are required to work through the process of creating top ranked portfolios for each scenario, test sensitivities, calculate Monte Carlo results, and determine reliability needs. This section describes the resources PNM used for this work.

Supplemental Models and Data Assembly Tools

PNM used a variety of sources to create input values for each of the models described below. These included PNM's budgeting system, revenue requirements models, load forecasting models and other data systems. These range from Excel spreadsheets to complex database analysis programming systems. Each of the two SJGS scenarios required input assumptions for the costs to operate and maintain existing resources and the costs to acquire, operate, and maintain any new resource option. For resource retirement scenarios and sensitivities, this also requires calculating future asset values and value recovery costs in the spreadsheets.

Strategist Model

PNM licenses a commonly used capacity expansion model called Strategist from ABB to estimate top ranked resource portfolios. Strategist is a comprehensive, long-range resource planning tool for electric utilities. PNM used this tool for top ranked portfolio estimations for all scenarios, sensitivities, and Monte Carlo calculations.

The Strategist model utilizes a proprietary, dynamic programming algorithm to conduct a rigorous evaluation of up to 5,000 unique resource portfolios and selects and ranks the resource portfolios based on various user-specified criteria. It can model a wide range of resource alternatives such as energy efficiency and demand side alternatives, storage technologies, renewable and thermal generating units, various types of power purchase and sales agreements, and the electric market. The model identifies the top ranked resource portfolio based on NPV of total utility costs while meeting loads within reliability requirements, emissions mandates, construction limitations, and RPS and energy efficiency requirements.

Input data include fuel price projections; new resource construction costs; demand and energy forecasts and load shapes; energy efficiency projections; resource performance characteristics such as dispatchability, transmission capacity attributes, resource retirements, planned outages; and other relevant inputs. The model optimizes portfolio selection by calculating capital requirements, fuel costs, and O&M costs using economic dispatch to meet demand and energy requirements for each of the thousands of portfolio options and ranking each by the NPV of total utility cost. The model considers the existing resource portfolio and new resource options when determining the MCEP for a given scenario. PNM hosted a detailed presentation from ABB on how Strategist works and its capabilities at the November 10, 2016, Public Advisory meeting.

AuroraXMP

PNM licenses AuroraXMP from EPIS. AuroraXMP is a widely used economic dispatch model that evaluates portfolio economic dispatch on an hourly basis. This is an improvement over the typical week approach used for economic dispatch within Strategist. PNM used AuroraXMP to verify the fuel-mix implications illustrated in the Strategist results, particularly natural gas dispatch within key scenarios or sensitivities and to perform a portion of the reliability analysis. The reliability analysis suggests several strategies to maintain reliability, namely holding back generation for regulating reserves or curtailing dispatch from must run resources. PNM used AuroraXMP to evaluate different regulating reserve strategies to determine the optimal mix of natural gas resources in the MCEP and to help identify sources of value for energy storage resources.

SERVM

Under a consulting agreement with Astrapé Consulting, PNM used the SERVM model to update reserve margin and reliability metrics from the loss of load probability analysis. SERVM is a combined resource adequacy and production cost simulation model. The Southern Company originally developed SERVM in the 1980s and has enhanced it several times over the ensuing decades. It has been used in studies that have been filed with state regulatory commissions in Mississippi, Florida, Georgia, Alabama, Kentucky, South Carolina, North Carolina, and California to support target reserve margins and other resource adequacy related planning decisions. In addition to its use in regulatory proceedings, SERVM is used by many other planning organizations to inform resource adequacy decisions.

SERVM has more capability to perform reliability risk assessments than Strategist, AuroraXMP, or other traditional capacity expansion models because it models intra hour dispatch. As recommended in the *NERC Generation and Transmission Reliability Planning Models Task Force Final Report on Methodology and Metrics*, resource adequacy assessments should adhere to minimum simulation requirements such as hourly chronological load modeling, accounting for load forecast uncertainty and random forced outages of generation capacity, and transmission modeling that recognizes major transmission constraints. SERVM fully meets all these requirements. While the above recommendations are for a specific nationwide resource adequacy assessment, the industry generally follows these recommendations. Most planning organizations in the United States use either SERVM or the GE MARS software for determining target reserve margin levels and resource adequacy planning needs and additional models to determine long-term expansion plans.

ANALYSIS RESULTS

ANALYSIS RESULTS

As described earlier, PNM evaluated two primary scenarios in this IRP: an assumed continuation of SJGS in PNM's supply portfolio (SJGS Continues) through the planning period and an assumed shutdown of the plant after the summer peak in 2022 (SJGS Retires). The two scenarios create very different needs for future resources. Figure 32 and

Figure 33 illustrate the future needs required to meet demand at 4:00 p.m. on a hot summer day, which represents PNM's historic system peak hour. If SJGS continues in operation, there is much less need for new resources compared to the retirement scenario.

Figure 32. SJGS Continues Scenario: Generation Mix by Fuel Type

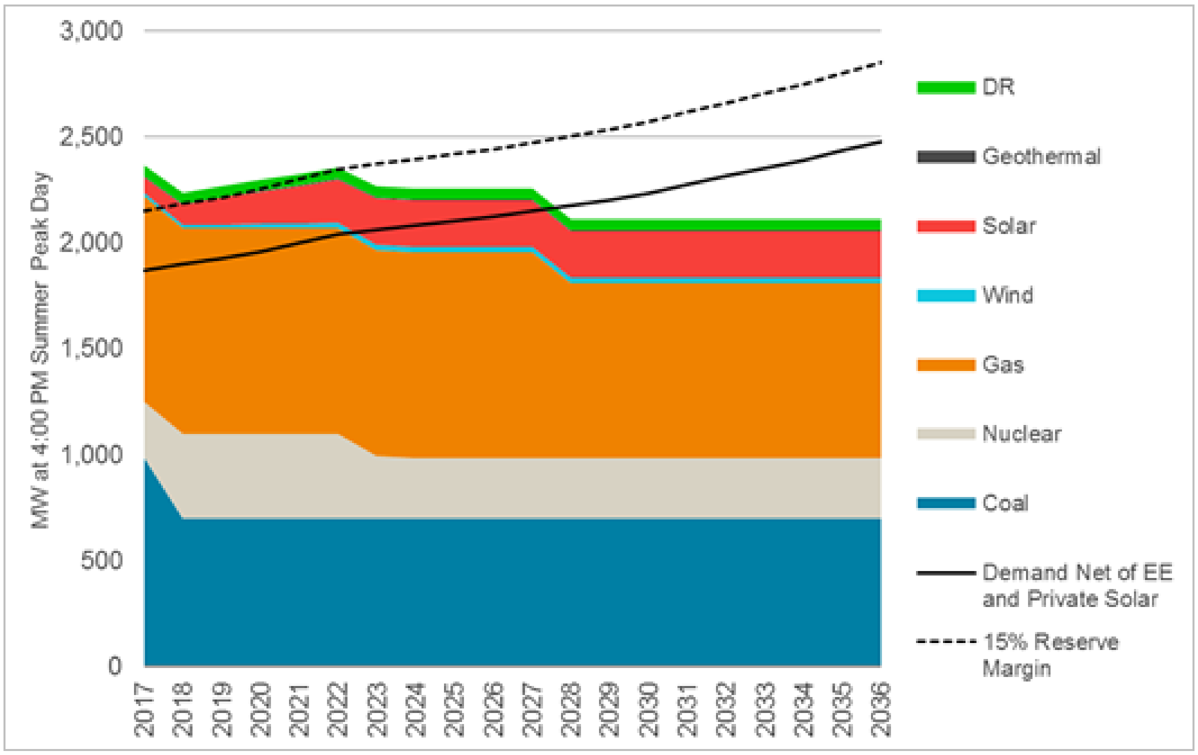
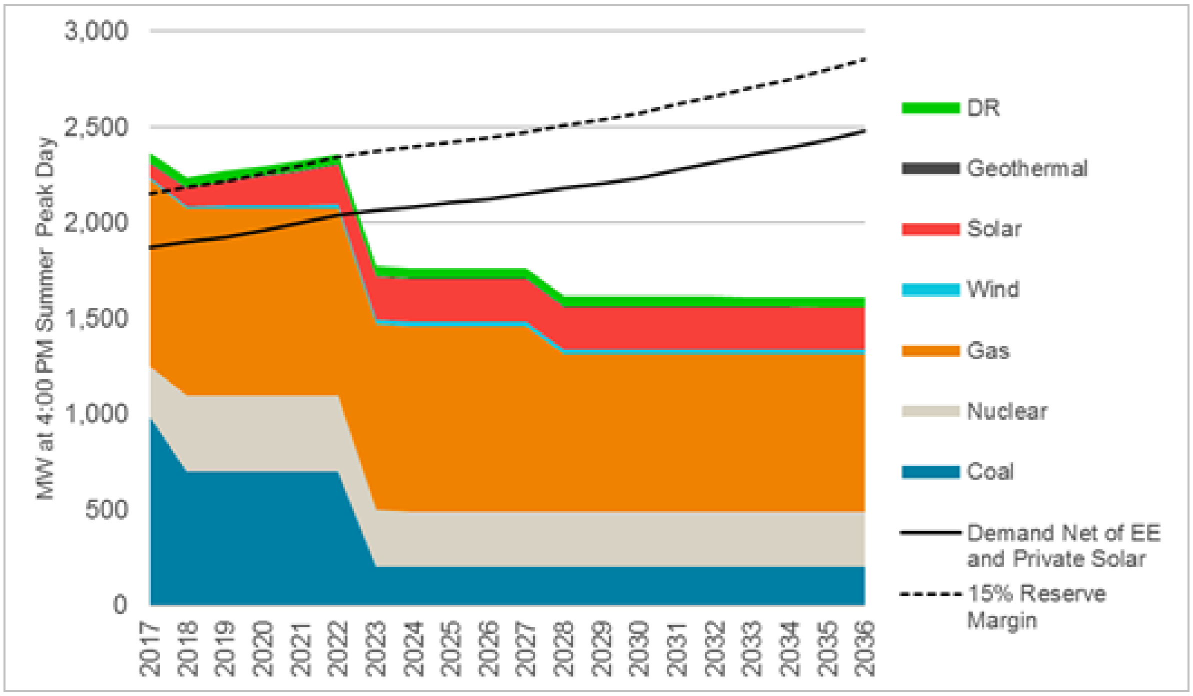


Figure 33. SJGS Retires Scenario: Generation Mix by Fuel Type



In addition to looking at the historic peak hour, the demands on PNM's system are changing. With the addition of significant solar resources available to meet the 4:00 p.m. load, the drop in availability may be larger than the drop in loads by 8:00 p.m. on a hot summer day. In the past, PNM met system reliability needs and ensured sufficient summer peaking capacity was available. As supply and demand relationships change with existing generation retirement, energy efficiency, and private solar resource growth along with new universal solar and wind generators, PNM needs to ensure sufficient capacity is available at every hour of the year.

PNM examined these changing needs through its scenario and sensitivity analysis, economic dispatch modeling, and Monte Carlo risk analysis within the two primary scenarios. Because the needs within these two scenarios are so different, this IRP presents the analysis results for both scenarios separately.

SJGS Continues Scenario

The SJGS Continues scenario assumes Units 1 and 4 will continue to operate after 2022 and through the end of the planning period. Units 2 and 3 will be retired at the end of 2017.

New resource additions in the continuation scenario are driven by replacement of expiring PVNGS leases, the Valencia and New Mexico Wind Energy Center PPAs, and maintaining planning reserve margins while supplying load growth. PNM compared the type of resources added against reliability measurements to ensure requirements for planning reserves, regulating reserves, and contingency reserves were all met before constructing the MCEP for this scenario.

Top Ranked Portfolios

PNM used the Strategist model and the database of existing and potential resource options to build portfolios using 21 scenarios of load, gas, and carbon pricing for the SJGS Continues scenarios. Appendix L shows the top ranked portfolios that meet reserve requirements for each of the 21 scenarios.

Load Scenarios

Resource additions in the mid-load scenarios of the SJGS Continues portfolios are needed if capacity is reduced by not retaining the PVNGS-leased capacity in 2023 through 2024, and the expiration of the Valencia PPA in 2028. The top ranked plans under the mid-load scenarios include gas peaking capacity followed by a combination of gas peaking and renewable energy resources.

This relationship between resource retirements and replacements is also consistent in the low and high-load scenarios. In the low-load scenario, reserve margins remain higher through the PVNGS lease expirations and the mix of gas peaking and renewable energy resources begins after the end of the Valencia PPA. Because the load growth in the low-load scenario is much less than the mid-load scenario, no renewable resources are added. In the high-load scenarios, gas peaking capacity is added and reserve margins are maintained with a combination of gas peaking capacity and renewable energy resources.

Gas and Carbon Price Scenarios

The gas and carbon price assumptions have the impact of changing the mix of renewable and gas peaking resources added to maintain reserve margins in the three load scenarios. Higher gas and carbon price assumptions favor more carbon free energy resources. In low price scenarios for gas and carbon, gas peaking capacity is favored over the carbon free resources.

SJGS Retires Scenario

The SJGS Retires scenario is characterized by the assumption that the two units of the SJGS station that will continue operating after 2017 will cease operation after the summer peak load period in 2022.

Retiring SJGS capacity after the 2022 summer peak creates a significant need for replacement resources. Replacement resources are a mix of gas peaking, and renewable resources. PNM compared the type of resources added against reliability measurements to ensure requirements for planning reserves, regulating reserves, and contingency reserves were all met. Appendix M shows the top ranked portfolios meeting reliability requirements for each of the 21 scenarios which informed the decision for the final MCEP.

Top Ranked Portfolios

PNM built portfolios for the SJGS Retires scenarios using the same gas price, load, and carbon price scenarios as described above in the SJGS Continues scenarios. The coal cost forecast used was created using the existing coal supply agreement. Appendix M shows the top ranked portfolios that meet reserve requirements for each of the 21 scenarios.

Load Scenarios

Retiring SJGS capacity after the 2022 summer peak creates a significant need for replacement resources starting prior to the summer peak in 2023. The SJGS capacity is replaced by gas peaking resources and the energy is partially replaced by renewable resources. The mix of these resources is affected by the load forecast assumptions. In the mid-load scenario with mid gas and carbon assumptions planning reserve margins are low through 2026, and in the period of 2023 through 2026, the replacement options for SJGS capacity include hundreds of MW of solar resources, and gas peaking capacity. The high-load scenarios add natural gas combined cycle capacity to the potential replacement mix in 2023. In the low-load scenarios, replacements are limited to natural gas peaking capacity, unless natural gas and carbon emissions are expensive. If natural gas and carbon are expensive, the low-load scenarios include renewable resources in addition to natural gas peaking capacity.

Gas and Carbon Price Scenarios

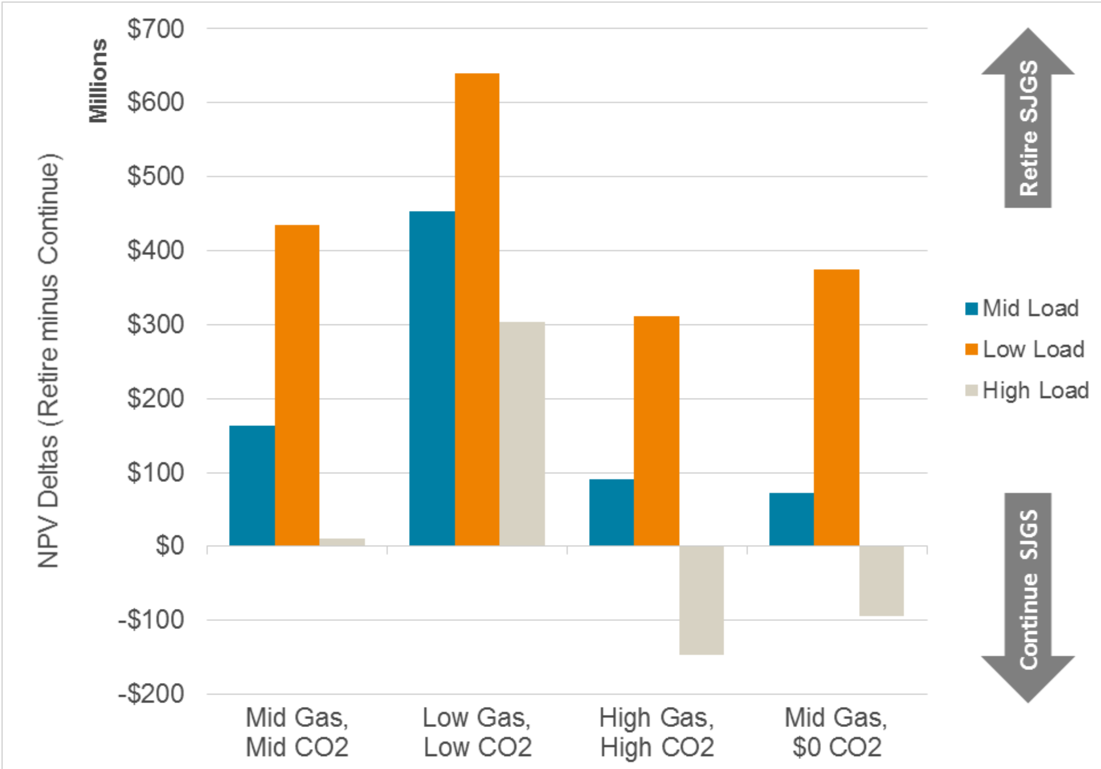
The gas and carbon price assumptions have the impact of changing the mix of renewable and gas resources added to replace SJGS capacity in all three load scenarios. Higher gas and carbon price assumptions favor more carbon free energy resources, including more renewable energy and retention of the PVNGS leases. In low price scenarios for gas and carbon natural gas combined cycle capacity replaces carbon free resources.

Comparison of SJGS Retires to SJGS Continues Scenario

A comparison of the net present value of costs for the two SJGS scenarios shows that under most of the combinations of load, natural gas and carbon prices examined, there is a long-term cost savings for PNM’s customers if PNM exits SJGS in 2022. The magnitude of the savings is dependent upon the load, natural gas and carbon prices, but the conclusion that retiring SJGS will provide cost savings is based upon the value of moving from the fixed cost energy supplied by SJGS to a variable cost portfolio of renewable energy and traditional resources that better matches the future load forecast.

Figure 34 shows the difference between the net present values of continuing and retiring SJGS. A positive value occurs when it is less expensive, over the 20-year planning period analysis, to retire SJGS in 2022 than to continue operations through the planning period. The four groups of bars are four combinations of natural gas and carbon prices. The three bars within each group show the result for a given load forecast within each combination of gas and carbon pricing.

Figure 34. Comparison of SJGS Retires vs. Continues



The scenarios that favor continuing SJGS are only select high-load scenarios, specifically scenarios with (1) high-load and high gas and carbon prices and (2) high-load, mid gas prices, and no carbon price. These scenarios were built with the assumption that a second data center will locate within PNM's service territory. PNM did not assume new renewable resources will be linked with this second data center load, but considers it in the sensitivity analysis, discussed later in the report. This is true even in the high natural gas price scenario.

Carbon prices are based on the combined set of gas and carbon prices provided by PACE for this IRP. The high carbon price from the PACE price curves is lower than the carbon prices required by the NMPRC in the Standardized Carbon Rule for IRPs. A higher carbon price than reflected in the graph above would increase the differential in net present values in favor of retiring SJGS.

In the NMPRC-approved stipulation that results in SJGS Units 2 and 3 retiring at the end of 2017, PNM is required to purchase solar or wind credits or allowances for every MWh produced by 197 MWh of SJGS beginning January 1, 2020. This obligation is avoided if PNM divests SJGS capacity after January 1, 2018. The price to purchase these credits is unknown, the cost is capped at $7 million per year. The comparisons provided above include the assumption that PNM would pay $2.50 per MWh, which is a price based on a 2016 request for REC bids, for the credits required in all of the SJGS Continues scenario. There are no costs associated with this obligation in the SJGS Retires scenarios. If the cost for the credits is higher than $2.50 per MWh, the differential in net present values in favor of retiring SJGS would increase.

PNM also tested the impact of no carbon price over the twenty-year planning period. Similar to the scenarios using the PACE price curves, the assumption of no future carbon costs is not as significant to the results as PNM's current load forecast. Figure 35, Figure 36, and

Figure 37 compare the results of the Monte Carlo analysis for the SJGS Continues and SJGS Retires scenarios (NPV Risk (5% Tail)). The SJGS Retires portfolios are more dependent on variable resources and variable costs associated with natural gas. Understandably, the Monte Carlo analysis shows that SJGS Retires scenarios have a higher probability of varying costs over the twenty year planning period.

Figure 35. Monte Carlo Results - NPV Risk (5% Tail) for Mid-Load Scenarios

Figure 36. Monte Carlo Results - NPV Risk (5% Tail) for High-Load Scenarios

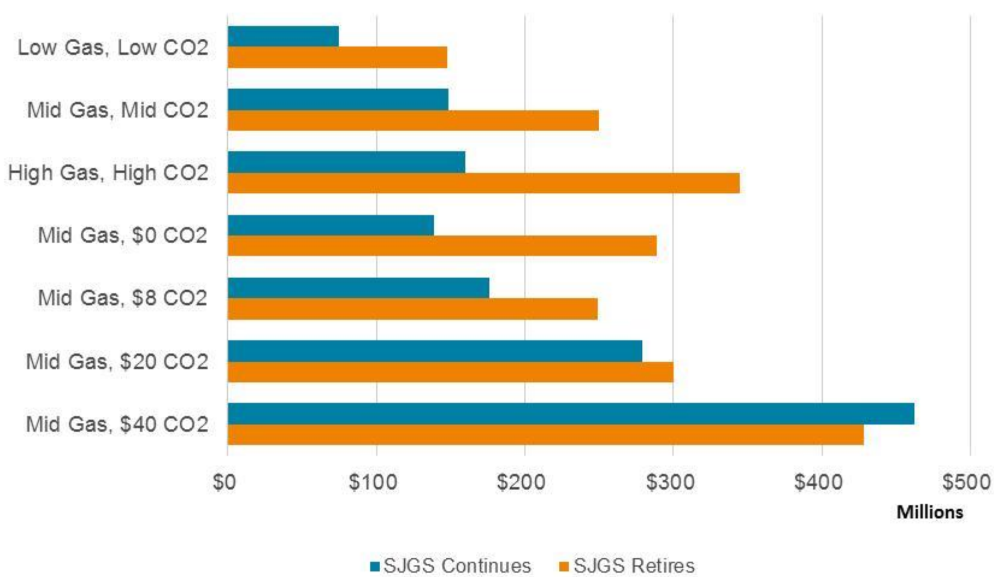
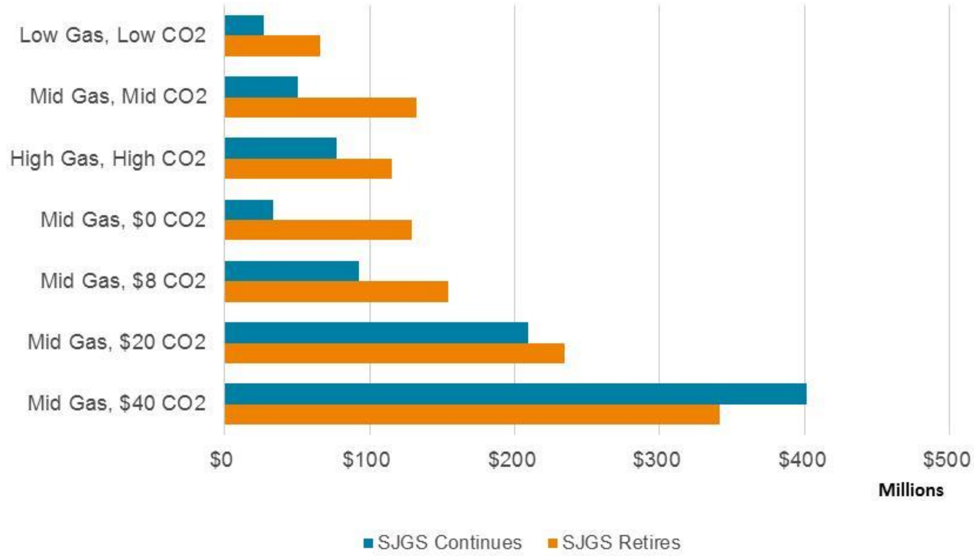


Figure 37. Monte Carlo Results - NPV Risk (5% Tail) for Low-Load Scenarios



Economic Dispatch

PNM has been able to make wholesale off-system sales to other utilities and power marketers from excess generation and the revenue from those sales has benefitted PNM's customers through credits included in the fuel charges on their monthly bills. To understand the impact of retiring SJGS on this benefit in the future, PNM performed economic dispatch modeling using the AuroraXMP model. Based on the modeling results, reducing the baseload supply from the portfolio may reduce future off system sales margins on the order of $1.7 to $2.4 million dollars per year. This compares to 2016 margins of $2.3 million. Future off system sales revenue projections are extremely speculative and depend on the availability of power at market hubs that PNM utilizes for wholesale transactions. The potential reductions in off system sales margins assumed adequate market liquidity in the future and that the future projections for power and natural gas prices are accurate. If the current trend of declining market liquidity continues, the inability to use wholesale transactions to optimize resource utilization may have a more significant impact on future fuel costs than the reduction in baseload capacity from PNM's generation portfolio.

Sensitivities Analysis

PNM tested a range of resource assumptions and future cost estimates within the capacity expansion modeling. The resources tested and the techniques used are based on expected portfolio impacts for the types of resources and types of risks associated with each sensitivity. PNM considered a wide range of variables affecting its current baseload resources of SJGS, FCPP and PVNGS. PNM's load profile is changing; therefore, PNM anticipates the MCEP will require a mix of different resource types than the historical portfolio. Several of the sensitivities are designed to understand the best resources to replace coal generation being eliminated from the portfolio. Detailed results for all of the scenarios are included in Appendix O.

The other sensitivities are cost variables that should be considered due to their potential to impact future service costs but do not exhibit the type of variability that is best evaluated with a Monte Carlo analysis. Figure 38 and Figure 39 illustrate the tornado diagrams for the two primary scenarios for each of the sensitivity variables examined. The diagrams illustrate the importance of the load forecast and natural gas costs, which are scenario defining variables and are also evaluated in the Monte Carlo analysis. Other potentially significant variables like coal and nuclear costs do not vary as much as load and natural gas prices, so PNM considered the risk associated with these variables using sensitivity analysis. The following are short descriptions of each of the variables for sensitivities that were studied:

- Load Forecast: shows the range of costs using the low, mid, and high energy forecasts described in the "Customers" section of this report.
- PACE Gas/CO2: shows the impact of the range of natural gas and CO2 prices
- Energy Market: shows the range of costs or savings due to the ability to make off-system sales and purchases using a range electric market prices
- 0$ CO2: shows the cost reduction if carbon price is zero versus the mid CO2 price
- High/Low EE: shows the range of costs across the low, mid, and high energy efficiency forecasts
- No Integration Cost: shows magnitude of the impact of including integration costs in the cost of new renewable resources in the capacity expansion modeling

Figure 38. SJGS Continues Tornado Diagram

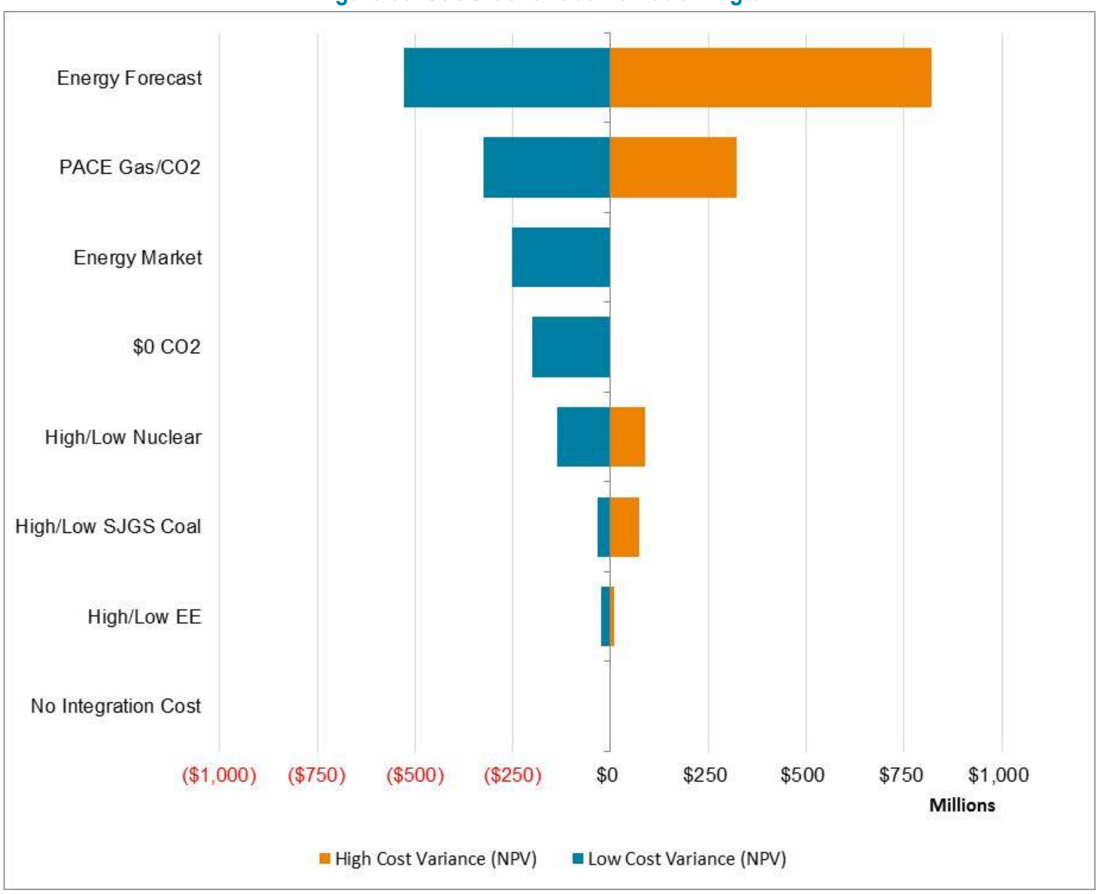
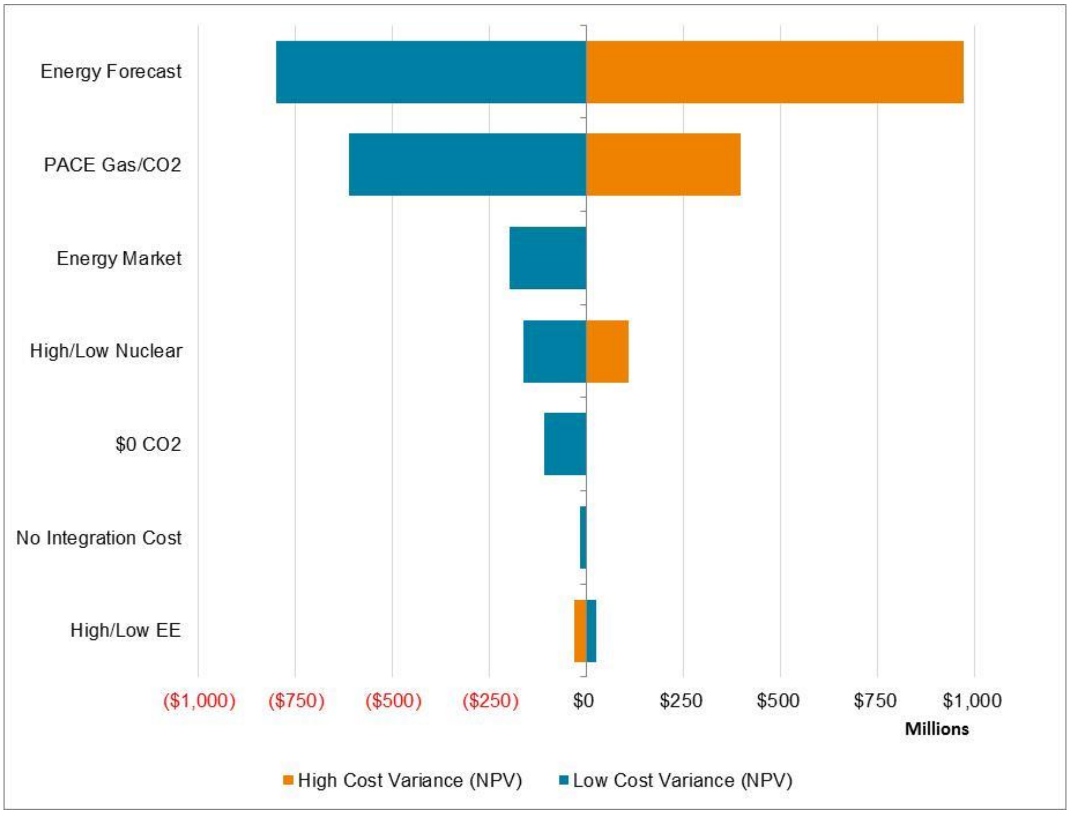


Figure 39. SJGS Retires Tornado Diagram



FCPP 2031 Retirement

A comparison of the net present values of retiring Four Corners in 2041 also shows the potential for long term cost savings for PNM's customers should PNM retire its Four Corners capacity in 2031. The Four Corners retirement sensitivity does not impact the SJGS Continues scenario prior to 2031 and does not impact the resource options selected to replace capacity in the SJGS Retires scenarios. Figure 40, Figure 41, and **Error! Reference source not found.** illustrate the NPV cost results for each sensitivity performed on each load forecast for each SJGS scenario.

Figure 40. FCPP Sensitivity Mid-Load Forecast NPV Cost Comparisons

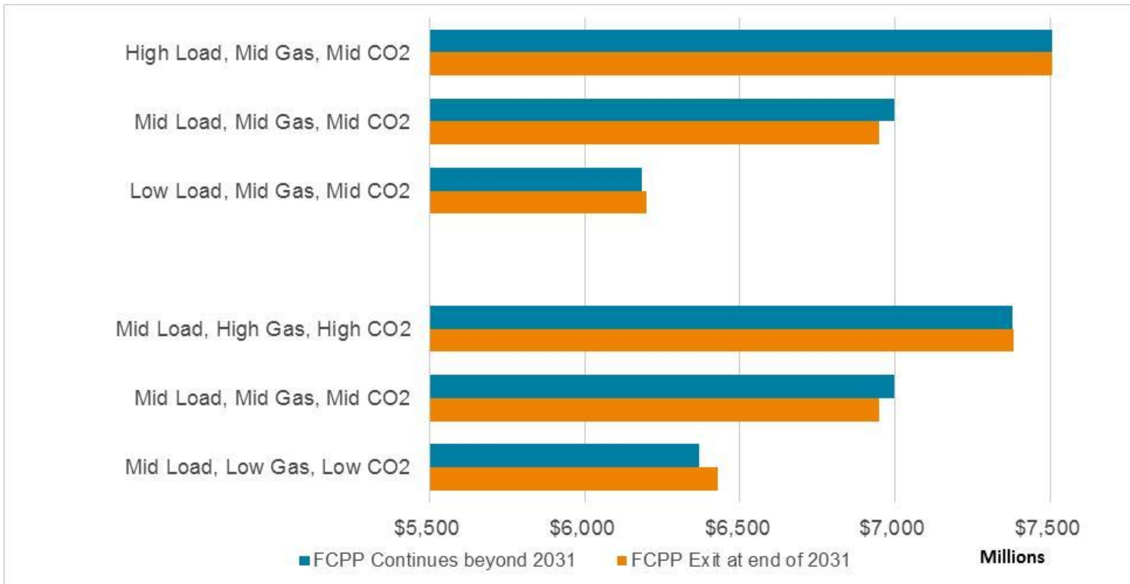
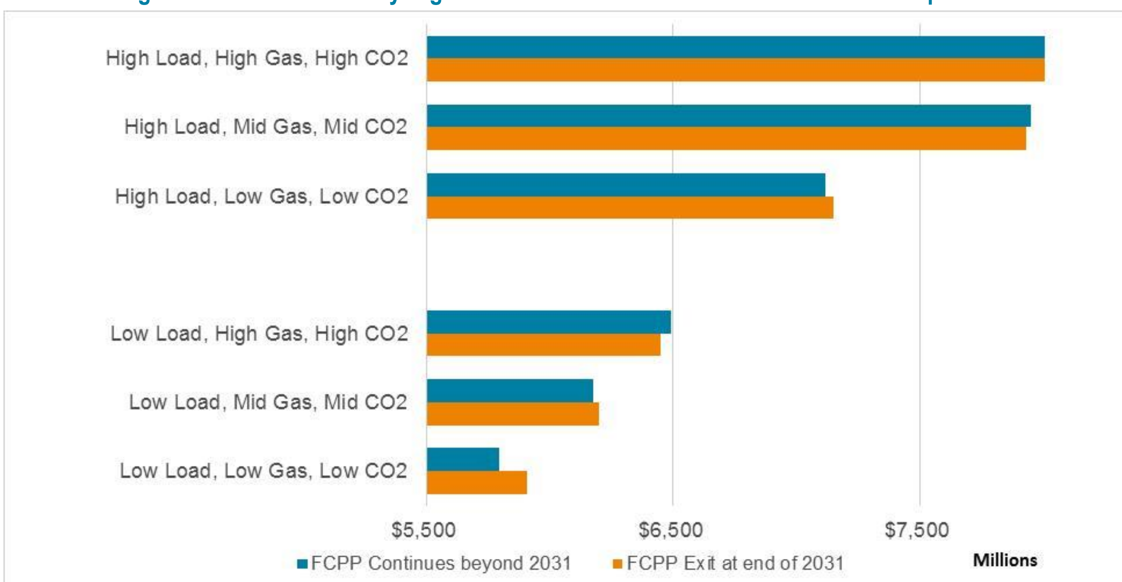


Figure 41. FCPP Sensitivity High-Load and Low-Load Forecast NPV Cost Comparisons



PVNGS-Leased Capacity

The price and terms at which PNM can retain the PVNGS-leased capacity beyond lease expirations are unknown. The capacity expansion modeling shows that the PVNGS leased capacity can be included in the top ranked portfolios for the SJGS shutdown case if PNM can repurchase the leased capacity from the lessors. If SJGS continues, the lease purchases are not included in the top ranked capacity expansion modeling. If SJGS and Four Corners are retired, Palo Verde will be the only baseload resource in PNM's resource portfolio. If the leases are not retained, PNM baseload capacity will drop to 488 MW in 2024 and 288 in 2032, while minimum baseload system demands range from 600 to 700 MW. Retaining the leased capacity will maintain 402 MW of carbon-free baseload in the portfolio after 2024 and 2031.

Figure 42 illustrates the NPVs of each sensitivity and Figure 43 shows the NPV risk tail of each sensitivity.

Figure 42. PVNGS Sensitivities Mid-Load Forecast NPV Cost Comparisons

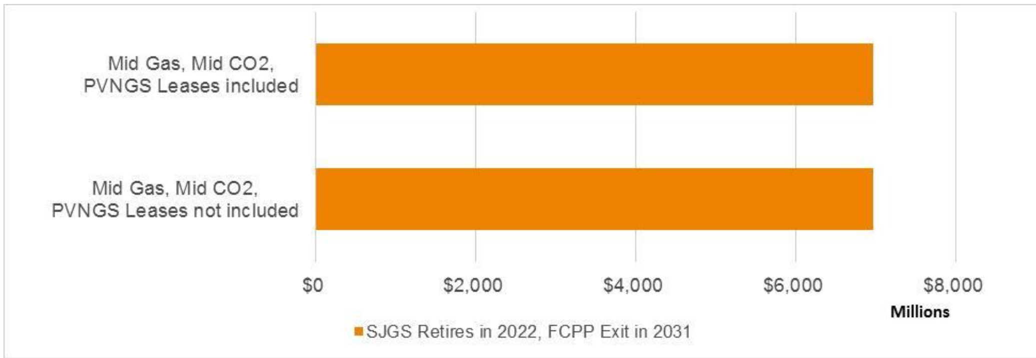
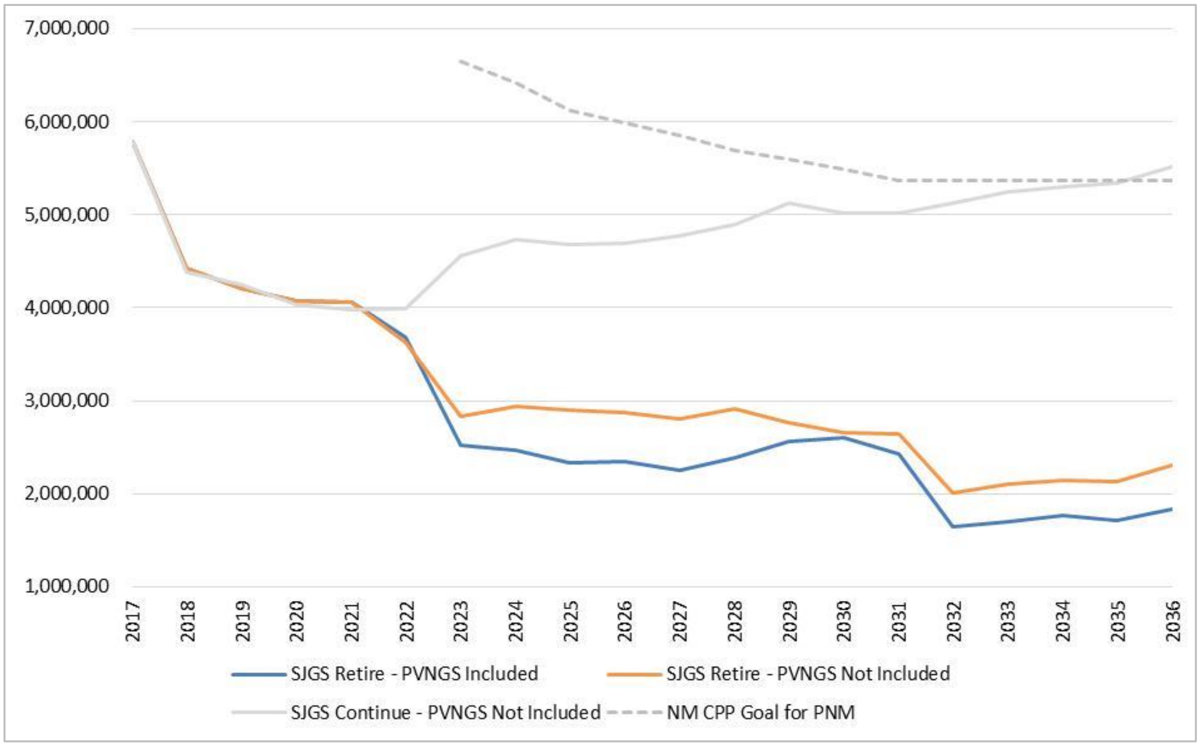


Figure 43. NPV Risk (5% Tail) for Mid-Load PVNGS Sensitivities

Whether the PVNGS-leased capacity is included in the MCEP has implications for overall portfolio carbon emissions, loss of load probabilities, and the range of economic risk indicated by the Monte Carlo analysis. Without the PVNGS-leased capacity, PNM's supply portfolio will be more dependent on natural gas. Carbon emissions will be higher, and the cost to operate the portfolio will be more susceptible to volatile natural gas prices and the potential for carbon regulation requirements. This results in both higher carbon emissions and more cost risk associated with volatile natural gas prices. Figure 44 shows the carbon emission profile if the leased capacity is retained compared to carbon emission if the nuclear energy is removed from the supply portfolio. The MCEP evaluation illustrates these relationships and explains why retaining the PVNGS leases is included in the MCEP.

Retaining PVNGS leased capacity also minimizes freshwater use, with lease retention lowering freshwater use by 5.6 billion gallons over the 20-year analysis period.

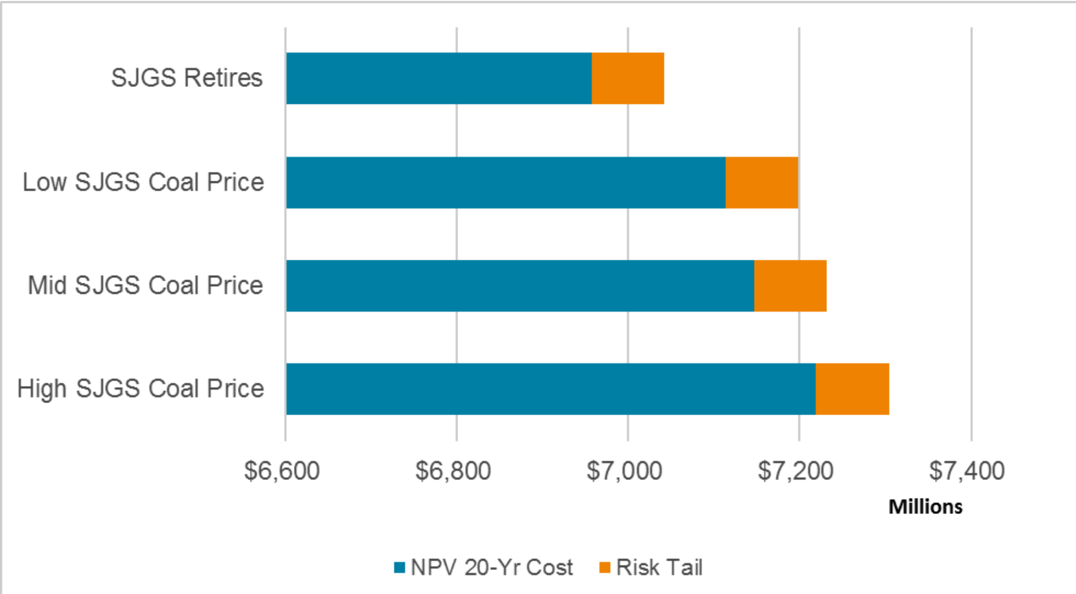
Figure 44. Tons of CO_2 With and Without PVNGS



SJGS Coal Prices

As shown on the tornado diagrams (Figure 38 and Figure 39), the SJGS coal prices have a more significant impact in the SJGS Continues scenario than the retirement scenario. PNM tested different coal price curves against the San Juan Continues scenario. These resulting portfolios of the capacity expansion modeling are shown in Figure 45 for the mid, high and low coal cost sensitivities using the mid gas and CO_2 pricing curves. Under all pricing conditions, the portfolio and resource selection remains unchanged over the entire planning period. Changing the coal cost does affect the dispatch order, but not resource selections. Also, the cost differential between the mid and low range is not significant enough to change the conclusion in the SJGS Continue versus SJGS retire scenario analysis.

Figure 45. SJGS Coal Price Sensitivity Results



Nuclear Fuel Price and O&M Range

Base load power plants, particularly nuclear plants, generally have low variable costs compared to their fixed costs . Fixed costs include a plant's original acquisition cost, fixed O&M expenses, and fuel at a nuclear plant. Because PVNGS represents a significant share of PNM's generation, PNM conducted a sensitivity analysis to assess variances in future fixed O&M costs and nuclear fuel prices using the base case assumptions for PVNGS.

The base case projections for PVNGS' annual fixed O&M and nuclear fuel expenses are based on the Arizona Public Service's projected budget for PVNGS. High- and low-cost sensitivity cases were defined as additions or subtractions from the base case amounts for each year, 2017 through 2036. PNM also ran Monte Carlo simulations of O&M expenses each year using historic O&M expense variation at PVNGS for the years 1995 through 2016. The low-case O&M cost for each year was set at the sixteenth percentile of the simulation draws and the high-case O&M cost was set at the eighty-fourth percentile. Nuclear fuel price projections for the low case assumed prices would increase at a slower rate than in the base case (0.5% per year lower) and at a higher rate for the high case (1.0% per year).

For the SJGS continues scenarios, the high and low cost cases did not use resource portfolio selections that differed from the base case. Under SJGS Continues scenario, the high case adds $87 million to total costs and the low case reduces costs by $136 million. Under the SJGS Retires scenario, the high case assumptions increased total NPV costs from the base case by $108 million. The low case reduced costs by $163 million.

Energy Efficiency and Demand Response Program Continuation

Continuing the energy efficiency and demand response programs produces savings both in terms of overall portfolio cost and the need for system investment. Removing the impact of future energy efficiency and demand response programs from the energy and demand forecasts in either the SJGS Continues or SJGS Retires scenarios has the same impact on resource needs. Without the demand savings from the programs, 40 MW of additional gas peaking capacity is needed in 2018 and another 41 MW in 2020. The NPV cost of ceasing program implementation reflects the avoided annual spending on program budgets, offset by the higher costs for replacement energy and capacity, This is calculated on the SJGS scenarios using mid-load, gas and carbon assumptions. The savings associated with future program implementation is almost double in the SJGS Retires scenario compared to the SJGS Continues scenario.

- SJGS Continues Scenario NPV savings from EE & DR programs: $71 million
- SJGS Retires Scenario NPV savings from EE & DR programs: $149 million

Energy Efficiency Standalone

In addition to examining the impact of ceasing the EE & DR programs, PNM looked at the impacts that would result from a more or less effective program. That is, what if the same program budget produced a much higher level of energy savings or much lower level than is expected? Energy efficiency program savings can help delay or eliminate the need for additional resources in the future. As such, PNM conducted a separate energy efficiency sensitivity (excluding demand response) under the SJGS scenarios to determine if resource additions would be impacted if PNM achieved more or less savings than the EUEA goal.

SJGS Continues

For the SJGS Continues scenario, varying energy efficiency savings does not affect portfolio additions until at least 2027. Later in the portfolio, as the energy efficiency program grows, planned gas resource additions are delayed. This is expected because the assumed energy efficiency savings more closely resembles a base load resource and, therefore, offsets coal generation, reducing costs, CO_2, and water emissions. These sensitivities confirm that over time, greater energy efficiency savings do impact the timing of PNM resource additions and reduce overall system costs to customers, making it an important resource in PNM's portfolio at all levels tested. Table 27 shows these results.

Table 27. SJGS Continues EE Sensitivity Results

Mid Load scenarios	Portfolio Cost ($NPV)	Difference from Mid EE Forecast ($NPV)
Mid Gas, Mid CO2, High EE Forecast	$7,122,257,281	($24,260,031)
Mid Gas, Mid CO2, Mid EE Forecast	$7,146,517,313	$0
Mid Gas, Mid CO2, Low EE Forecast	$7,156,090,516	$9,573,203

SJGS Retires

The savings achieved by energy efficiency directly impacts portfolio costs because it reduces the loads that need to be served. Portfolio costs will vary according to total savings. (See Table 28). In the low energy efficiency sensitivity, the portfolio costs are higher because more resources are needed to serve load. For this sensitivity, the PVNGS lease purchase and other gas plants and solar additions are replaced by a single combined cycle of a greater capacity in the near term and the combined cycle addition effectively eliminates any resource needs for the next two years until the reserve margin dips. Otherwise, the majority of the near term decisions remained unchanged.

In the high energy efficiency sensitivity, costs, CO_2 emissions, and water usage are all lower than in the base or low energy efficiency cases. The higher energy efficiency savings supplies baseload energy savings to the portfolio; which is less costly than building new resources to supply the energy. However, unlike the low energy efficiency sensitivity, the high energy efficiency portfolio does not significantly differ from the base case until 2027 to 2029, when wind and a gas addition are delayed due to the higher energy efficiency savings. Overall, in the SJGS Retires scenario, only the low energy efficiency case affects PNM's next resource addition decision.

Table 28. SJGS Retires EE Sensitivity Results

Mid Load scenarios	Portfolio Cost ($NPV)	Difference from Mid EE Forecast ($NPV)
Mid Gas, Mid CO2, High EE Forecast	$6,926,975,266	($29,852,328)
Mid Gas, Mid CO2, Mid EE Forecast	$6,956,827,594	$0
Mid Gas, Mid CO2, Low EE Forecast	$6,982,079,281	$25,251,688

EE and LM Program Capacity Value

On April 14, 2017, PNM filed for approval of its 2018 Energy Efficiency and Load Management Program Plan (2018 Plan). At that time, PNM estimated the avoided capacity value for energy efficiency and load management programs as $80 per kW-year, and this value was used to demonstrate the cost effectiveness of the 2018 Plan. Re-calculating this value for the SJGS Retires scenario shows the value of avoiding capacity additions to be $129 per kW-year. The higher value than estimated for the 2018 Plan is attributable to a greater need for replacement capacity if SJGS retires. Continuation of the programs is included in the MCEP because of PNM's requirement to provide cost-effective EE and LM programs under the Efficient Use of Energy Act and because they are cost effective as demonstrated in the sensitivity analysis.

Natural Gas Type Size and Price

The database of potential new resources includes a representative selection of a wide range of combustion turbine, reciprocating engines, and combined cycle technologies. The capacity expansion model selects combustion turbines in its top ranked portfolios when flexible capacity is most needed. The model selects reciprocating engines in its top ranked portfolios when the system requires both capacity and more energy than is typically supplied by a combustion turbine. While the combined cycle alternatives did not appear in the top ranked capacity expansion portfolios, these technologies are among the resources included in the top ten of the lowest cost of the thousands of portfolios generated.

PNM analyzed a variety of sizes and pricing to help isolate whether unit size factors into the model affect decisions to include natural gas combined cycle (NGCC) technology in the top ranked portfolios. Using the EPRI TAG database as a starting point for combined cycle technology, PNM characterized several sizes. In response to public comments, the initial list was extended to include a new highly efficient H Frame series gas turbine technology. This technology has yet to be installed in the United States. The new H Frame series includes larger sizes and higher efficiencies than the current combined cycle designs (based on F series) that PNM assumed in its new resource database. For the H Frame series sensitivity analysis, PNM modeled the following sizes of combined cycle designs: F Frame series sizes (at full output and at costs for existing units); larger H Frame series sizes with full output at 405 MW of capacity, PNM's half participation at 202.5 MW of capacity; quarter participation at 135 MW, and a sixth participation at 67.5 MW. Assumptions for installed cost and performance are found in Appendix K for all these technologies. Since there is not a need for baseload resources in the SJGS Continues scenarios, PNM only performed this sensitivity for SJGS Retires scenarios, where baseload or intermediate duty cycle resources are more likely to be needed. Table 29 shows the results of this sensitivity analysis.

Table 29. Sensitivity Results for NGCC Sizing and Price

Capacity	500 MW at existing costs	405/203 MW at new install	135/68 MW at new install	250 MW at crossover	500 MW at crossover
Series	Frame F	Frame H	Frame H	Frame F	Frame F
Installed Price	$700/kW	$1,005/kW	$1,005/kW	$338/kW	$170/kW
SJGS Retires					
2022					
2023		✓ (203 MW)	✓ (135 MW)	✓	✓
2024					
2025					
2029			✓ (68 MW)		
2032					

The results for this sensitivity analysis are shown in Table 29. PNM found that, similar to the smaller and higher cost CTCCs, a larger size CTCC with lower costs per kW than assumed for the base case was still not selected in for the top ranked portfolios. PNM tested both the 250 and 500 MW size CTCC's at different costs to find the price at which they would be selected which were $338/kW and $170/kW, respectively, less than a third or a quarter of current cost estimates. The results from testing the H Frame series CTCC's revealed different results due to better heat rates and economies of scale resulting from the larger sizes. When PNM included these options assuming purchase of a "share" of a larger plant, the technology was chosen as early as 2023 and was selected again in 2029. These results demonstrate that a combination between price and size could change near term resource additions. It is, however, based upon speculative pricing and assumptions since H machines are new and undemonstrated. First-in-class installed costs often run higher than initially estimated. Also, the assumptions rely upon PNM finding willing participants.

Solar Sensitivity

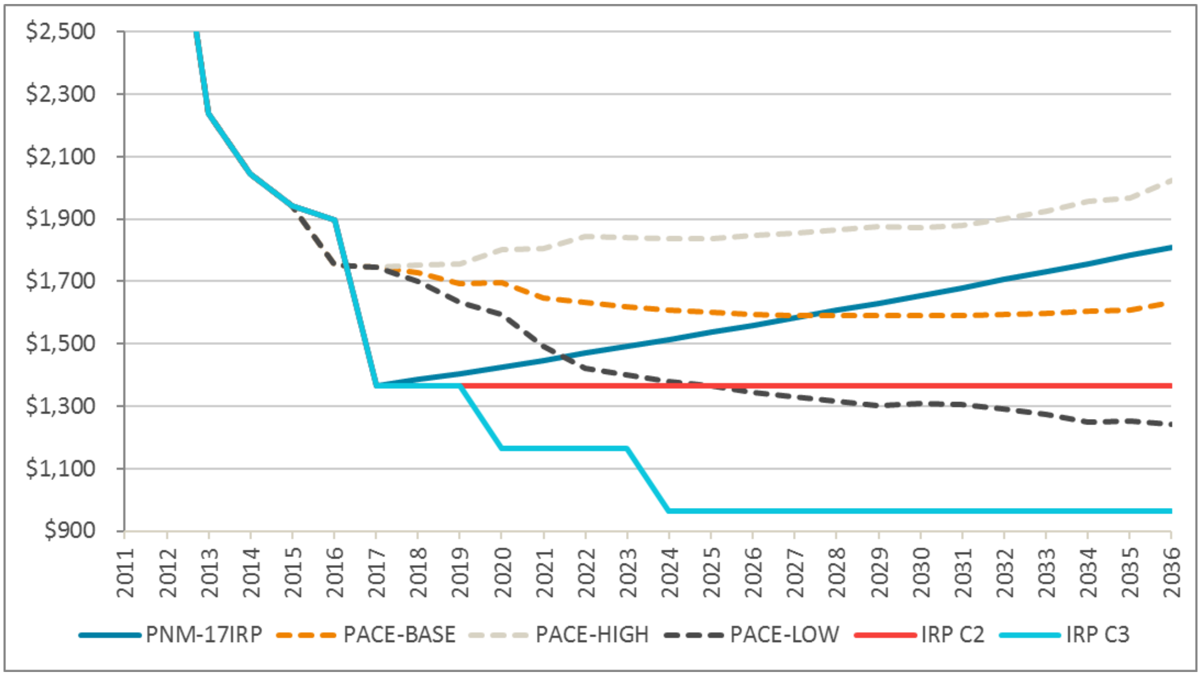
Solar prices have been steadily declining since PNM first began installing utility scale solar in 2011. Recent request for proposals (RFPs) show that prices for photovoltaics continue to decline. Since New Mexico has abundant solar potential it is important for PNM to understand the impact of lower solar prices and the role it plays in resource selection since it could greatly impact a portfolio. PNM conducted sensitivity analysis on solar pricing to be able to quantify how the price of solar affects resource selection.

Two important factors that can affect the timing and amount of solar are in the capacity expansion results are the costs and the effective load-carrying capacity (ELCC). For the costs, PNM evaluated the current and capital cost to install solar as well as the role of tax subsidies in the future; for the ELCC, PNM analyzed how existing and new solar additions in the future could shift the peak hour. For this solar sensitivity PNM did not analyze the need to add conventional resource additions or include integration costs to mitigate reliability problems that could occur when the renewable supply levels increase (this is discussed in the Reliability Analysis section). This sensitivity focused on the role of solar pricing in moving solar resource additions earlier or changing resource needs in the near term than occurs in the capacity expansion modeling using current cost estimates. An explanation of ELCC and the other performance characteristics considered is provided in Appendix K.

Pricing

PNM's past solar pricing assumptions all come from responses to RFPs. At the beginning of the 2017 planning process PNM relied on PACE forecasting to develop pricing curves as shown in the figure below. However, recent market data from the most current RFP issued in the first quarter of 2017 attracted even lower prices than forecasted. Therefore, to conduct this sensitivity PNM relied on the most recent RFP data to develop the cost curves in comparison to the PACE forecasts as shown in Figure 46.

Figure 46. Installed Solar Cost Assumptions ($/kW)



Since the RFP data only provides point estimates it is important to develop pricing estimates for solar in the future. PNM started with the point estimate and created three price curves. In keeping with current modeling practices and to remain consistent with all other resource alternatives in the database, the starting point was escalated at 1.5% annually (see curve PNM-17IRP in Figure 46). At a minimum, this means that relative to other technologies, solar PV maintains the same relative cost differential in year 20 as in year one. Cost Curve 2 was used to estimate a flat pricing curve (see curve IRP C2); however, in comparison to other alternatives this represents a declining cost curve as all other technologies are escalating at 1.5% annually. Finally, Cost Curve 3 was developed to represent significant cost savings should the market prices keep declining (see IRP C3). These three pricing curves set the foundation for the solar sensitivity analysis PNM conducted.

Federal tax incentives for installing solar facilities change during the planning period as shown in Table 30. PNM assumed the 30% investment tax credit extends in perpetuity in the PNM-17IRP price curve.

Table 30. Solar Investment Tax Credits

Solar in Service	Federal Tax Credit
<2020	30%
2020	26%
2021	22%
>2021	10%

Solar Sensitivity Results

Using the SJGS Continues and SJGS Retires scenarios PNM modeled three pricing curves to assess impacts on portfolio additions. The results for this sensitivity are summarized in in Table 31.

Table 31. Solar Sensitivity Results

Pricing Curve	Solar Additions (MW)	Solar Additions Allowed (MW)
SJGS Continues		
PNM - 2017 IRP	100	250
Cost Curve 2	200	250
Cost Curve 3	550	1,250
SJGS Retires		
PNM - 2017 IRP	250	250
Cost Curve 2	750	850
Cost Curve 3	600	1,250

Under Cost Curve 2, which assumes flat pricing, capacity expansion modeling results include all available solar resource additions in the top ranked portfolios. Therefore the sensitivity was rerun for both SJGS scenarios, allowing more solar resource additions, to find the optimum additions. For SJGS Continues, no more than the original 250 MW of solar was included in the top ranked portfolio when additional resources are available. For SJGS Retires, the amount included increased to 400 MW. Using Cost Curve 3, a declining price assumption, up to 550 MW more solar was included in the SJGS Continues top ranked portfolios and 650 MW in the SJGS Retires portfolios showing that solar pricing changes the amount of solar chosen for the top ranked portfolios.

Under the SJGS Retires for all pricing curves (see Table 32), the solar resource additions are not affected until a declining solar price is used. In the SJGS Continues case all near term resource decisions remain the same as solar additions only enter the top portfolios after 2028. This is likely due to over generation in those scenarios. Lower solar pricing primarily affects portfolios in the SJGS retire case; however, these pricing curves do not replace any of the near term resource additions shown in the top ranked portfolios. The portfolios show a declining overall net present value because of the solar resource additions added later in the planning period are replacing coal and natural gas fuel sources that are rising in cost relative to the solar costs.

Table 32. Solar Sensitivity Results by Pricing Curve

	Base Case	Cost Curve 2	Cost Curve 3
SJGS Continues			
2023-2024			50 MW
2025-2026			100 MW
2027-2028			
2029-2030	50 MW	50 MW	200 MW
2031-2033			150 MW
2034-2035		100 MW	50 MW
2036-2037	50 MW	50 MW	
SJGS Retires			
2023-2024	50 MW	50 MW	50 MW
2025-2026	100 MW	50 MW	200 MW
2027-2028		50 MW	
2029-2030	50 MW	50 MW	200 MW
2031-2033		300 MW	150 MW
2034-2035	50 MW	250 MW	

Solar Power Tower

The solar resource tested in the sensitivity analysis is photovoltaic technology. Other solar technologies exist such as solar thermal which employ the use of a steam turbine to generate electricity. Public advisory discussion included a request to review the solar power tower technology for possible use at the SJGS. PNM performed another sensitivity using solar power tower technology instead of photovoltaic. A solar power tower steam turbine operates at lower pressures and temperatures than subcritical coal plants, so retrofitting this technology at SJGS does not appear to be a feasible option. For this sensitivity PNM assumed a brand new solar power tower facility would be built. Cost and performance details are provided in Appendix K and capacity expansion modeling results are in Appendix O. The result of this sensitivity showed that the solar power tower at today's market price would not be economic enough to be selected in the top ranking portfolios.

Wind Sensitivity

PNM tested a range of pricing, sizing and capacity factors to determine how these variables affect the timing and quantity of wind resource additions in an optimized portfolio. All sensitivities were performed for both SJGS Continues and SJGS Retires scenarios. Table 33 shows the combinations evaluated. For pricing sensitivity PNM assumed that any new wind could be obtained at flat pricing levels for 20 years and that all costs such as incentive costs, administrative, transmission service or transmission upgrades would also be included. This analysis also assumes sufficient transmission capacity is always available.

Table 33. Wind Sensitivity Results

	SJGS Continues	SJGS Retires
Pricing (2017 $/MWh)		
$46.85	✓ (base case)	✓ (base case)
$40.00	✓	✓
$30.00	✓	✓
$20.00	✓	✓
Wind Facility Size (MW)		
100 MW	✓ (base case)	✓ (base case)
50 MW	✓	✓
150 MW	✓	✓
200 MW	✓	✓
Wind Capacity Factor (%)		
45%	✓ (base case)	✓ (base case)
25%	✓	✓
50%	✓	✓

SJGS Continues

The wind pricing sensitivity shows that as the price for wind decreases; the wind resources are selected earlier in the planning period (see Table 34). Even though wind is available to be selected in Strategist as early as 2021, in no pricing sensitivity modeling run does it come into the top ranked portfolios in the first year available. These results show that wind costs need to be about half of what PNM's recent bids indicate for early portfolio addition. Even at the low pricing, other near term planning decisions are unaffected by the addition of wind resources.

Table 34. Wind Price Sensitivity Results on Wind Addition Timing in Continue SJGS Scenario

Timeframe	$46.85/MWh	$40.00/MWh	$30.00/MWh	$20.00/MWh
2023-2024				✓
2029-2030		✓	✓	
2035-2036	✓			

SJGS Retires

The wind pricing sensitivity in the SJGS Retires case results in the same conclusion as the SJGS Continues scenario: as pricing declines wind is selected earlier and traditional resource additions are unaffected. Early wind selection does, however, defer solar resource additions. Solar is selected in 2023 when wind is about $47/MWh. In general when the cost of wind falls, wind resources in the top ranked portfolios are included earlier and delay solar additions (see Table 35). This trend continues as wind prices decline, demonstrating that wind pricing will affect the timing of both wind and solar resources in the SJGS Retires scenario.

Table 35. Wind Price Sensitivity Results of Wind Addition Timing in SJGS Retires Scenario

Timeframe	$46.85/MWh	$40.00/MWh	$30.00/MWh	$20.00/MWh
2022				✓
2023			✓	
2025/2026		✓		
2029-2032	✓			

Wind Facility Size

Portfolio selection is not particularly sensitive to wind facility size (see Table 36). In the SJGS Retires sensitivities, wind sizes greater than 50 MW do not change the timing of wind additions in the top ranked portfolios. When wind resources are 50 MW, they are chosen sooner (as early as 2026). For SJGS Continues, wind additions are not chosen in the base case or any of the sensitivity top ranked portfolios. For both these scenarios; wind size makes little to no difference in the near term resource choices in the top ranked portfolios. Table 36 shows the timing when wind is selected in the portfolio at various sizes

Table 36. Timing Results of Wind Facility Size Variation

Wind Size	SJGS Continues	SJGS Retires
100 MW (base case)	Wind not included	2029/2032
50 MW	Wind not included	2026/2032
150 MW	Wind not included	2029/2032
200 MW	Wind not included	2032

Wind Capacity Factor

For all the sensitivity modeling runs, the wind capacity factor had no effect on near term decisions. Wind is selected as an economic resource late in the planning period. These results show that wind could be selected earlier in some cases (see Table 37). There is no clear trend as it depends largely on the mix of resources that are added prior to the wind resource additions.

Table 37. Timing Results of Wind Capacity Factor Variation

Capacity Factor	Continue SJGS	Retire SJGS
45% (base case)	Wind not included	2029/2032
25%	Wind not included	2027/2031
55%	Wind not included	2032

Of the three variables, pricing had the largest impact. Since wind economics is dependent upon how well the resource produces at a location; the pricing can be largely affected by economies of scale.

Combination of Wind Price/Size/Capacity Factor

All of the wind sensitivities performed above show that wind could be added to a portfolio as early in 2022. PNM performed further analysis to determine if larger wind facilities with higher capacity factors at lower costs could change the planned resource mix. PNM performed a sensitivity that included adding a 200 MW wind facility with 55% capacity factor, at a price of $20/MWh to the resource alternative database. PNM also allowed up to 400 MW of wind facilities to be selected to see if more wind capacity would defer any near term resource additions. For this sensitivity, PNM did not include any associated transmission upgrades or costs which would be needed to accommodate an additional 400 MW of wind in the top ranked portfolios. Table 38 shows the modeling results.

Table 38. Wind Addition Timing for Wind Price/Size/Capacity factor Sensitivity

Timeframe	SJGS Continues		SJGS Retires	
Year	100 MW Wind @45% CF	200 MW Wind @55% CF	100 MW Wind @45% CF	200 MW Wind @55% CF
2022	✓		✓	
2023				✓
2025		✓		

Renewable integration costs can play a role in when renewable resources are added to a portfolio. Under the SJGS continuation case no major changes to the portfolio occur until after 2028. After 2028, the addition of integration costs for solar result in delaying solar resource additions by one to two years in the later years of the planning period. Including wind integration costs in the capacity expansion modeling eliminates wind additions in the outer years. Because no near term resource additions are affected, the overall impact of adding renewable integration costs to the SJGS Continues case is considered minor.

Renewable Energy Integration Costs

Renewable integration costs can play a role in when renewable resources are added to a portfolio. Under the SJGS continuation case no major changes to portfolio occur until after 2028. After 2028, the addition of integration costs for solar result in delaying solar resource additions by one to two years in the later years of the planning period. Including wind integration costs in the capacity expansion modeling eliminates wind additions in the outer years. Because no near term resource additions are affected, the overall impact of adding renewable integration costs to the SJGS Continues case is considered minor.

For SJGS Retires, solar integration costs reduce the size of or delay renewable solar energy additions and accelerate conventional/wind resources in the 2025-2027 timeframe. Overall, similar to the SJGS Continues, adding renewable integration costs for wind delays wind additions only one year. As noted in the Four Year Action Plan section, PNM will re-evaluate the quantity and timing of solar additions in the MCEP after the conclusion of this IRP.

High Renewable Energy Supply Portfolio

A sensitivity analysis was conducted to examine the cost and risk impacts of a portfolio with a larger share of renewable energy generation than occurs in the top ranked portfolios. In the MCEP a total of 250 MW of solar and 200 MW of wind resources are added to the generation portfolio for SJGS replacement and in subsequent years. In the high renewable sensitivity case, 450 MW of solar and 400 MW of wind are added to the portfolio. Along with PNM's existing renewable resources and renewables slated to be added for RPS standards and to supply the data center customer, this sensitivity case produces a portfolio with approximately 1,740 MW of renewable nameplate capacity, plus customer-owned private solar resources.

When compared to the MCEP, the twenty-year NPV cost increase resulting from the high renewable portfolio is $120.3 million. This number does not include the need to construct additional transmission to support the wind resource additions. The higher renewable production does reduce the 20-year total of CO_2 emissions by 8.8 million tons by lowering generation from natural gas plants and the Four Corners plant. A larger supply of renewable generation needs to be supported by additional flexible generation resources that are not included in the capacity expansion modeling as discussed below in the reliability analysis section. The cost for additional flexibility is also not included in the NPV calculation for this portfolio.

Small Modular Nuclear Reactors

Small modular nuclear reactors (SMR) are potential future resources that offer a new source of carbon free power. The SMR technology is still in its infancy, having yet to receive full licensing from the Nuclear Regulatory Commission so this analysis is based on the assumption that SMR will have achieved full NRC approval and have obtained an operating license such that installation of this technology could occur by 2031. The SMR technology is modular meaning it can be easily sized to meet the resource need. This is attractive for meeting PNM's small annual incremental load increases. For this analysis PNM assumed three different sizes based on a core size of 48 MW: 48 MW, 96 MW and 114 MW. The results of the capacity expansion model show that SMR is not selected in the top ranked portfolios for either SJGS Continues or Retires for any year after 2031. Since SMR is still new PNM will revisit the state of the technology during the next IRP process to determine is any changes have occurred or developments within PNM that could make this technology viable.

High-Load Forecast Data Center Assumption

Assuming an increase in renewable energy supplied by a second data center in the high-load forecast affects resource options and the NPV of cost calculations in the top ranked portfolios. In comparing the SJGS Continues with the SJGS Retires scenarios, continuing SJGS fares best if loads correspond to the high-load forecast. The high-load forecast assumed an addition of a second large customer like the new data center customer. The optimized portfolios in these scenario comparisons did not assume a new large customer would also bring renewable energy similar to the existing data center customer. To test the impact of adding renewable energy along with the new large customer in the high-load scenario, PNM created an additional portfolio for the high-load case under the SJGS Continues scenario and for the SJGS Retires scenario by adding more renewable energy for that new large customer's loads. This sensitivity was completed using the mid gas and CO2 price forecasts. For the SJGS Continues scenario, the additional renewable energy for a new large customer increases the portfolio costs relative to the portfolio without additional renewable energy for a new large customer by $126 M. In contrast, the additional renewable energy associated with a new large customer lowers portfolio cost in the high-load scenario in the SJGS Retires case by $129 M. Including renewable energy associated with a new large customer in the high-load case results in the SJGS Retires scenario being the most cost effective.

Reliability Analysis

To analyze the dynamic nature of PNM's system, PNM contracted Astrape Consulting to analyze reliability and flexibility of the PNM system across a number of scenarios. Specifically, Astrape reassessed PNM's resource margin target to determine the baseline and see if PNM's current fleet was adequate enough to maintain reasonable resource adequacy. Secondly, Astrape analyzed impacts of increasing renewable energy supply on PNM's reliability metrics and the costs associated with doing so. Lastly, using the study results Astrape developed rules of thumb regarding additional flexible generation or additional operating reserves needed to maintain adequate reliability. To perform this study PNM requested two years be studied (2021 and 2024). The choice of these years was based on the results of the 42 base scenarios discussed earlier in the SJGS Continues and SJGS Retires Scenario Analysis Results sections since they represented large changes in PNM's fleet. By 2021, PNM's resource portfolio will adjust to comply with the 20% RPS. Additionally, a large amount of baseload generation is eliminated from the portfolio (SJGS Units 2&3) by 2018. These changes could impact reliability results, so PNM chose 2021 as the baseline to study reserve margin and understand reliability metrics. The year 2024 was also studied since large amounts of renewable energy are in top ranking portfolios if SJGS retires in 2022.

To understand how reliability is impacted when renewable energy supply increases; PNM requested additional analysis from Astrape. The following analyses were incorporated in to the work being performed by Astrape.

- Calculation of reliability metrics and developing rules of thumb for renewable levels as high as 80% in PNM's service territory.
- Assessment of the ability of battery storage in helping PNM maintain system reliability.
- Assessment of baseload capacity changes on reliability metrics when renewable supplies are increasing, Astrape modeled a scenario assuming SJGS Retires in 2022, PNM does not retain the PVNGS leased capacity and FCPP retires. This was performed to respond to a request from the Public Advisory group.

Appendix P has the full report and the study assumptions used for this analysis.

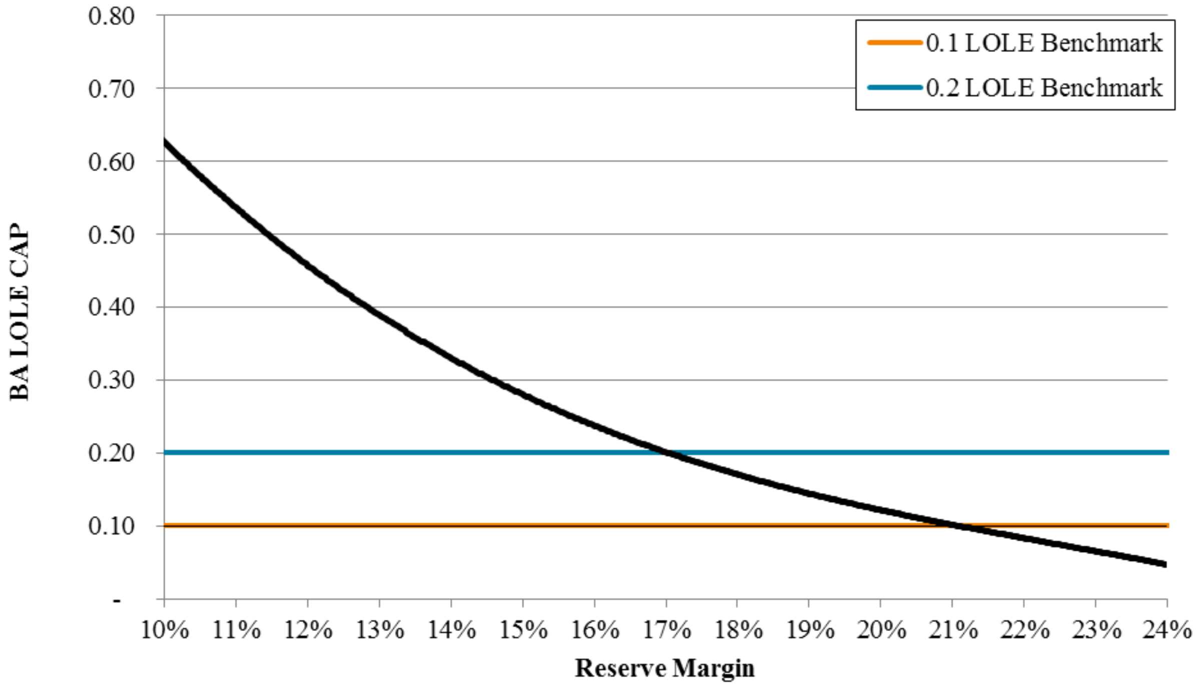
Strategic Energy and Risk Valuation Model (SERVM)

Astrape uses a chronological, production cost and reliability software called SERVM to capture the intrahour volatility of an operating grid within a balancing authority (BA). The SERVM software can perform over 11,000 yearly simulations at five-minute intervals to approximate the needs of a system over the entire year. Most capacity expansion modeling tools such as Strategist are not designed to capture the dynamic nature of resources such as wind as it can vary significantly within minutes. Strategist utilizes a simplistic dispatch algorithm and therefore cannot be use to understand PNM's operational needs.

Reserve Margin

PNM benchmarked the current portfolio to set a baseline for comparison. Working off the original 2013 Reserve Margin study (RMS), Astrape reassessed PNM's resource margin in light of the following new and potential portfolio changes since 2013: 84 MW of solar, 102 MW of wind, the elimination of 327 MW of coal generation and the addition of future renewables to accommodate the data center load and meet RPS goals. The 2013 Reserve Margin Study (RMS) identified a reserve margin of 15-17% as that which Astrape found to be needed in order to maintain a 2 in 10 year loss of load expectation (LOLE) standard given an LOLE of 0.2. The results for the updated modeling using 2021 as a base year are shown in Figure 47.

Figure 47. 2021 Reserve Margin Results



In order to maintain industry standards (i.e. a LOLE of 0.1), PNM's reserve margin would have to rise to 21%. Because PNM is a smaller utility with limited resources and limited interconnections, achieving an industry standard may not be economically justifiable. Astrape recommended that PNM could still maintain reasonable reliability with a LOLE standard of 0.2 for a reserve margin of 17%; however, PNM customers should expect twice the number of events. PNM's current reserve margin target is 13%, which was set during a time when intermittent renewable resources were a lower share of the resource portfolio.

Of additional concern, the market assistance PNM has long relied upon to help achieve shortfalls in resource adequacy is quickly drying up. This condition alone could force PNM to hold a higher reserve margin in order to maintain NERC compliance and shows that the current threshold for holding a 13% reserve margin is no longer adequate.

Baseline Reliability Metrics

Reliability metrics are designed to show how flexible a fleet is responding to load variations or unexpected events that could occur for various reasons, using the terms $LOLE_{flex}$ and $LOLE_{cap}$. Together these two metrics are used to characterize the ability of the fleet to respond to variations caused by load or caused by the intermittent nature of renewable resources. PNM used these metrics to assess the capability of PNM's fleet to respond to events caused by not having enough available resource capacity ($LOLE_{cap}$) and events caused by not being able to respond quickly to meet the volatile nature of renewable resources ($LOLE_{flex}$).

As shown in in Table 39, PNM's mid-load forecast $LOLE_{flex}$ in 2021 remains within an adequate reliability range assuming $LOLE_{flex}$ of 0.2 and small amounts of renewable curtailments. The table illustrates that if PNM maintained a 3% load following target at a lower cost, it would experience poor reliability ($LOLE_{cap}$ & $LOLE_{flex}$ exceed the 0.2). To maintain adequate reliability, PNM needs higher reserves, causing the existing fleet to run less efficiently to reduce events and maintain reliable thresholds. These results show that PNM could maintain adequate reliability in 2021, if PNM maintains a 7% load following target with the 2021 planned renewable energy supply and assuming full market assistance.

In 2024, renewable supply levels are higher, significant baseload capacity has been removed from the portfolio, and flexible gas generation has been added to the portfolio. The LOLE metrics indicate that 7% load following target maintains reasonable reliability with the planned 2024 renewable energy supply.

Table 39. Mid-Load Scenario: Reliability Impacts for Mid-Load in 2021 and 2024

Base Case	Renewable Generation	Renewable Supply	LF Target	Renewable Curtailment		$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
Year	**GWh**	**% of Load**		**% of Renewable**	**MWh**	**Events Per Year**		**$millions**
2021	2,322	17%	3%	0.83%	19,579	0.165	1.02	$339.3
2021	2,322	17%	5%	0.97%	22,833	0.141	0.25	$343.6
2021	2,322	17%	7%	1.11%	26,265	0.138	0.16	$348.0
2024	2,714	19%	3%	0.86%	23,800	0.095	1.74	$473.5
2024	2,714	19%	5%	0.98%	26,952	0.075	0.38	$478.8
2024	2,714	19%	7%	1.11%	30,453	0.072	0.10	$483.9

Increasing Renewable Additions

Astrape further assessed PNM's fleet for increasing renewable resources. The goal of this analysis was to show impact on the flexibility metrics from increasing renewable energy supplies. Increments of 10% were included in a baseline portfolio up to a level of 80%. These results are shown in Table 40.

Table 40. Reliability Impacts of Increasing Renewable Penetration

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

The table shows that reliability would significantly degrade before 40% renewable penetration is reached and costs are significantly higher once 50% penetration is reached. A further consideration is that increasing renewable supply is accompanied by increasing curtailment of these resources. At levels of 50%, incremental renewable resources added to the system will be curtailed 14-20% of the time because resources will exceed loads at certain times. These results assume a liquid market for buying and selling additional energy is available, which may not be the case. An inability to buy and sell easily would result in more renewable energy curtailment. Based on this analysis, PNM would require additional flexible generating capacity to accommodate additional renewable resource supplies beyond 20% .

Energy Storage Assessment

A potential solution to maintain reliability at higher renewable supply levels was discussed during the public advisory meetings. Energy storage, such as batteries, offer flexible capabilities to allow for needed flexibility. Astrape compared reliability and costs of quick start gas turbine technology (LMS6000 gas fired peaking units) to battery storage installed in 2024. The results for a 19% renewable energy supply portfolio are provided in Table 41. Here the results presented do not show any significant impact to the $LOLE_{flex}$ events for various degrees of battery storage sizes for renewable penetration level of 19% compared to adding flexible generation to the resource portfolio. Adding additional flexible generation or energy storage show only a slightly lower cost which would have to be weighed against the capital cost of the energy storage resource.

Table 41. 2024 Reliability Comparisons at 19% Renewable Supply

	Renewable Generation	Renewable Supply	LF Target	Curtailment		$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	GWh	% of Load		%	MWh	Events Per Year		$millions
Base Case	2,714	19%	5%	0.98%	26,952	0.0747	0.38	$478.78
Base Case and 2 LM6000 (80 MW)	2,714	19%	5%	0.92%	25,306	0.0300	0.32	$475.85
Base Case and 100 MW 2-hour storage	2,714	19%	5%	0.92%	25,206	0.0863	0.38	$477.06
Base Case and 100 MW 4-hour storage	2,714	19%	5%	0.84%	23,019	0.0678	0.37	$475.87
Base Case and 100 MW 6-hour storage	2,714	19%	5%	0.85%	23,354	0.0788	0.31	$475.39

Table 42 shows the results of the same comparisions with 40% renewable energy supplies. Energy storage is more valuable to maintain needed reliability metrics, and with lower costs than flexible generation at a 40% renewable energy supply level, than it is at 19%.

Table 42. 2024 Reliability Comparisons at 40% Renewable Supply

	Renewable Generation	Renewable Supply	LF Target	Renewable Curtailment		$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	GWh	% of Load		%	MWh	Events Per Year		$millions
Base Case	5,493	38%	14%	11.46%	634,370	0.04	0.13	520.07
Base Case and 2 LM6000 (80 MW)	5,493	38%	14%	11.55%	638,933	0.02	0.13	517.14
Base Case and 100 MW 2-hour storage	5,493	38%	14%	8.72%	482,265	0.01	0.13	503.79
Base Case and 100 MW 4-hour storage	5,493	38%	14%	8.18%	452,470	0	0.12	500.73
Base Case and 100 MW 6-hour storage	5,493	38%	14%	8.07%	446,422	0.01	0.1	500.6

Impact of Baseload Generation on Reliability Metrics

As part of the public advisory process, PNM was requested to perform an additional reliability run to take into account the loss of SJGS, FCPP and the PV leases. This amounted to eliminating 811 MW from PNM's existing fleet from the portfolio. To accomplish this scenario, PNM ran the capacity expansion software to determine the top ranked portfolio that would be needed to meet demand and the reserve margin requirements (See Appendix O). That portfolio was then provided to Astrape to analyze the flexibility metrics. The results for this scenario are provide in Table 44.

For this scenario, the flexibility metrics improve moving from an already acceptable 0.16 $LOLE_{flex}$ to 0.03 $LOLE_{flex}$ and there is only slight improvement from a capacity standpoint (from a 0.04 $LOLE_{cap}$ to 0.03 $LOLE_{cap}$) under the 7% load following. Renewable curtailments reduce slightly by approximately 3,000 MWh. While the flexibility metrics have improved, the balancing area costs are $70 million higher for 2024 alone due to the increased reliance on natural gas facilities to replace the baseload reduction. Additionally, these costs from the SERVM model do not include any fixed or capital costs associated with new resource replacements or undepreciated asset recovery costs associated with the additional baseload plant removal from the portfolio.

Table 43. 2024 Reliability Metrics for Public Advisory Scenario – loss of baseload generation

	BA/PNM Only Renewable Penetration	LF Target	Renewable Curtailment		$LOLE_{CAP}$	$LOLE_{FLEX}$	PNM Balance Area Costs
	% of Load		%	MWh	Events Per Year		$millions
2024 SJ, FC, PV Lease Retire Continues	17%/21%	3%	0.35%	8,537	0.04	0.68	503.8
2024 SJ, FC, PV Lease Retire Continues	17%/21%	5%	0.50%	12,166	0.04	0.1	509.5
2024 SJ, FC, PV Lease Retire Continues	17%/21%	7%	0.65%	15,881	0.03	0.03	515.4

Reliability Analysis Results Summary

Because PNM's future renewable and energy storage additions may change as technology assumptions change, Astrape developed guidelines for correlating renewable energy supply with likely reliability impacts. Figure 48 shows the changing $LOLE_{flex}$ associated with incremental solar and wind resources, assuming no significant energy storage resources. Predicted changes in LOLE and renewable resource curtailments are shown in Figure 49. PNM's system becomes more constrained when renewable energy supplies rise above 20%, as shown by the steep slope in the curve. This steep slope curve indicates, that unless flexible conventional resources are added, PNM will need to curtail renewable resources to maintain operating reserves at its minimum level of 7%. Accordingly, adding more renewables to PNM's system, absent the addition of flexible conventional resources, diminishes the value of the resources, and the graph shows that PNM would have to curtail roughly 48% percent of marginal renewable energy additions once PNM has reached a 40% supply. For every additional renewable resource added to PNM's portfolio, curtailments also rise to balance system operations.

Figure 48. LOLE$_{FLEX}$ with Increasing Renewable Supply (Load following @ 7% LF)

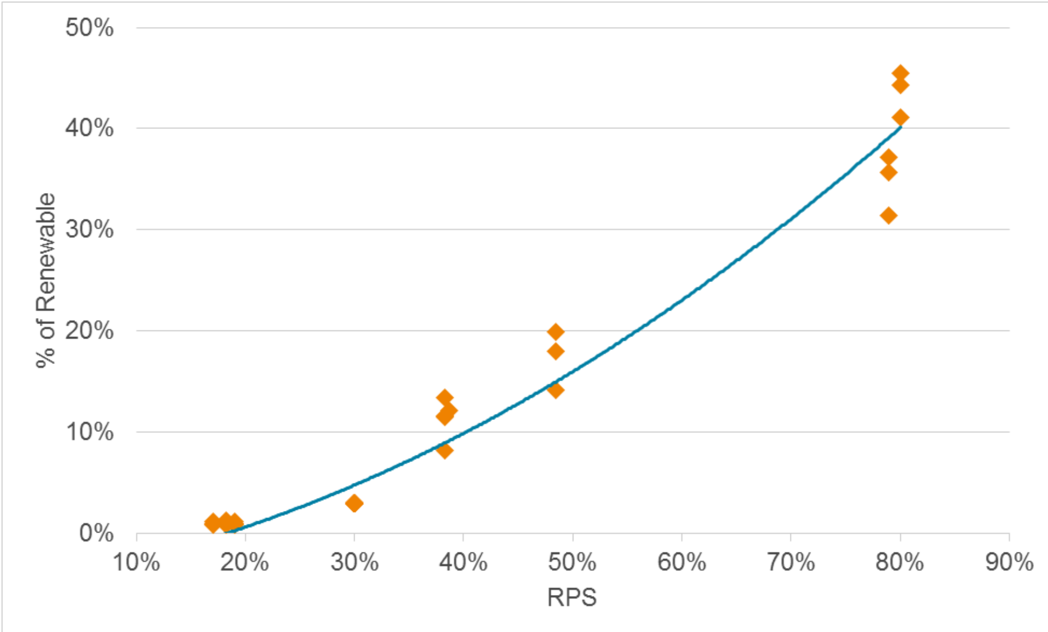
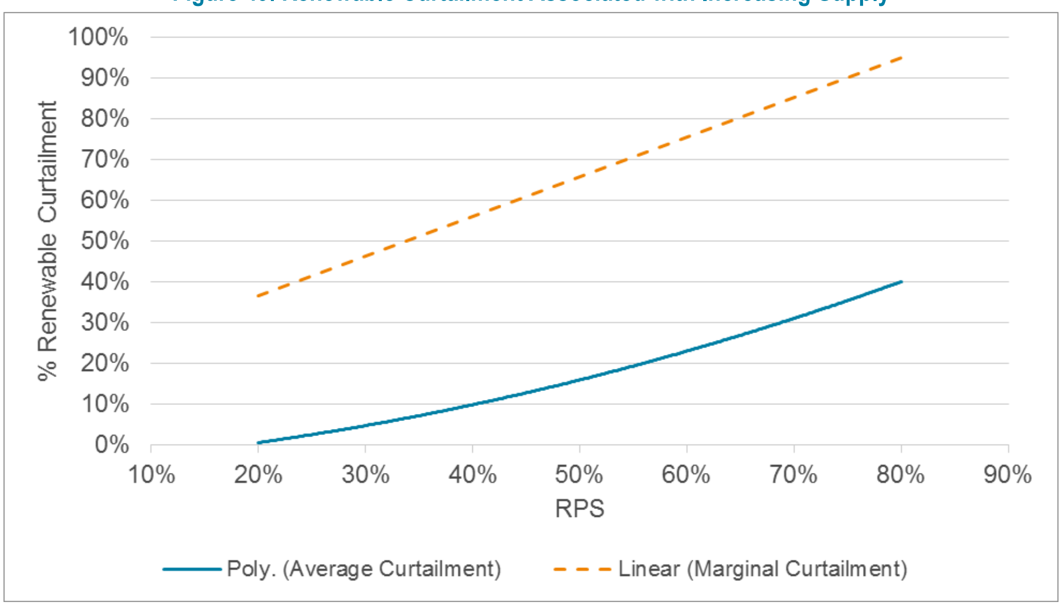


Figure 49. Renewable Curtailment Associated with Increasing Supply



Average Curtailment represents % of entire renewable fleet curtailed at each RPS level

Marginal Curtailment represents the % of the next additional renewable MW that would be curtailed at each RPS level

The study results show a 0.2 LOLE standard is met by requiring a 17.5% reserve margin and 7% load following. The modeled portfolios are also reliable when renewable curtailments are allowed. However, as renewable supplies increases to 40%, curtailment increases substantially along with the need for higher load following capacity. At this level of renewable energy supplies, energy storage also provides value in terms of both physical reliability and potential cost savings.

Most Cost-Effective Portfolio

To identify the MCEP for the period 2017 through 2036, PNM examined hundreds of thousands of potential resource portfolios, accounting for multiple scenarios and sensitivity studies of differing resources, economic conditions, carbon prices, and customer demands. PNM developed alternative scenarios for economics, fuel pricing, and customer demand levels to test the sensitivity of resource portfolio to alternative assumptions and conditions. PNM presented these analyses to the Public Advisory Group during several meetings.

PNM determined the MCEPs by assessing the top ranked portfolios for each scenario and considering the implications of the sensitivity analyses. Differences in the input assumptions between scenarios resulted in a different system resource portfolio mix. For example, high gas price scenarios resulted in portfolios with less reliance on gas-fired plants than portfolios recommended for low gas price scenarios. Sensitivity analysis shows how robust the portfolio choices are within reasonable ranges of input assumptions. Monte Carlo analysis highlights the financial risk associated with a portfolio in an uncertain future. The reliability analysis provides minimum portfolio capabilities needed for reasonable reliability expectations under a range of renewable resource addition assumptions. This analysis helped identify risk mitigation strategies and confirm the importance of individual resource types within the MCEP.

The scenario and sensitivity analysis support the following observations about PNM's future resource portfolio:

- Energy efficiency and demand response programs can cost-effectively reduce the need for supply side resources
- PNM should retire SJGS after the current operating agreements expire
- The retired SJGS capacity should be replaced with natural gas peaking capacity
- The natural gas peaking capacity that replaces SJGS must provide operational flexibility
- Battery storage is most valuable in high renewable penetration scenarios and can be a cost-effective replacement for flexible natural gas capacity
- Renewable energy resources should be added to provide carbon-free energy to reduce natural gas consumption after SJGS is retired.
- PNM should exit FCPP after the current operating agreements expire in 2031.
- PNM should retain the PVNGS leased capacity to ensure a reasonable supply of carbon-free baseload capacity is available after all of the coal-fired baseload is retired

Portfolios

Figure 50 illustrates the MCEP Capacity Additions and Retirements over the twenty year period. Table 44 shows the loads and resources plan for the first 10 years of the MCEP. A 20-year plan is included in Appendix N.

Figure 50. Capacity Additions and Retirements by Fuel Type

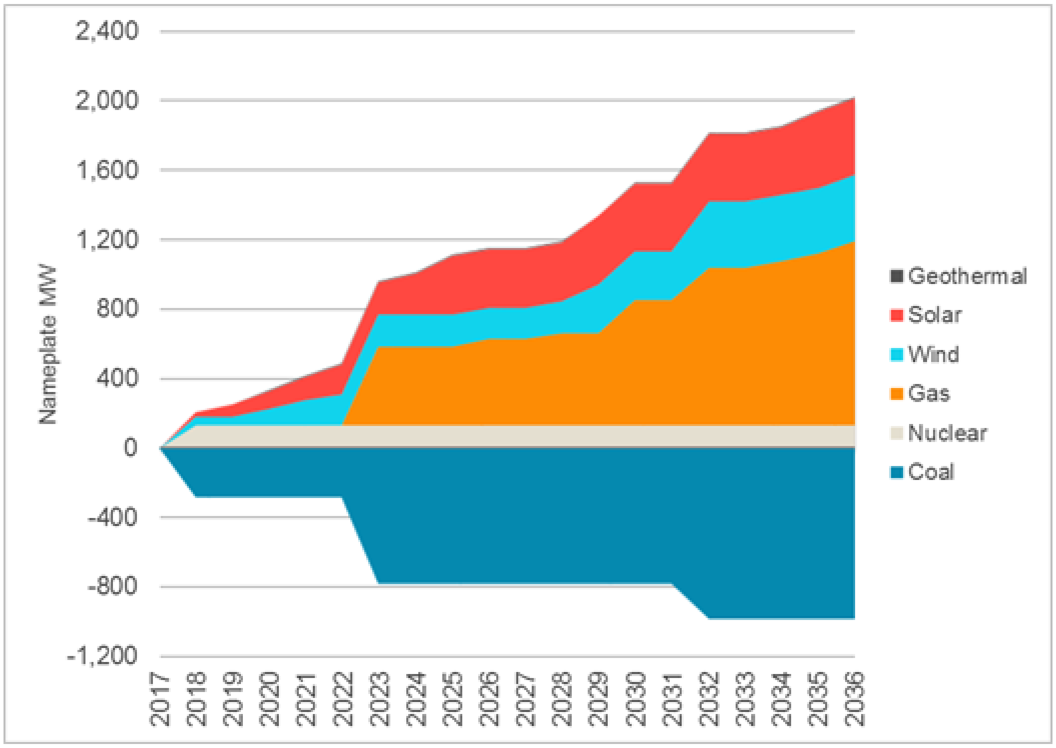


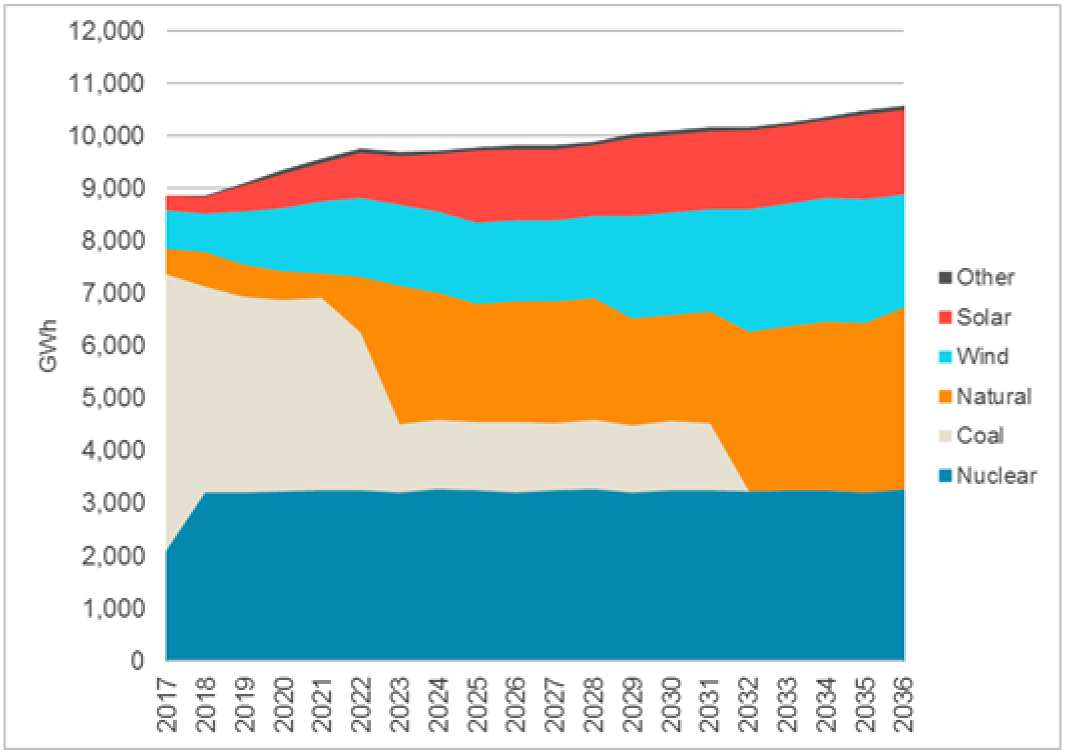
Table 44. MCEP Loads and Resource Plan

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Forecasted System Peak Demand	1,911	1,961	2,009	2,056	2,108	2,154	2,189	2,219	2,249	2,280
Forecasted Incremental Energy Efficiency	(23)	(36)	(51)	(63)	(77)	(89)	(103)	(113)	(120)	(129)
Forecasted Incremental Customer Sited PV	(18)	(25)	(32)	(32)	(32)	(33)	(34)	(35)	(36)	(37)
Net System Peak Demand (MW)	1,871	1,900	1,926	1,961	1,999	2,033	2,053	2,071	2,093	2,114
Four Corners	200	200	200	200	200	200	200	200	200	200
San Juan	783	497	497	497	497	497	-	-	-	-
Total Coal Resources (MW)	983	697	697	697	697	697	200	200	200	200
Palo Verde Unit 1 & Unit 2	268	268	268	268	268	268	268	268	268	268
Palo Verde Unit 3	-	134	134	134	134	134	134	134	134	134
Total Nuclear Resources (MW)	268	402	402	402	402	402	402	402	402	402
Reeves	154	154	154	154	154	154	154	154	154	154
Afton	230	230	230	230	230	230	230	230	230	230
Lordsburg	80	80	80	80	80	80	80	80	80	80
Luna	189	189	189	189	189	189	189	189	189	189
Rio Bravo	138	138	138	138	138	138	138	138	138	138
Valencia	150	150	150	150	150	150	150	150	150	150
La Luz	40	40	40	40	40	40	40	40	40	40
Natural Gas Fired Resource (intermediate)	-	-	-	-	-	-	-	-	-	-
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	-
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	-	-	-	40
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	41	41	41	41
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	41	41	41	41
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187
Natural Gas Fired Resource (peaking)	-	-	-	-	-	-	187	187	187	187
Total Natural Gas Resources (MW)	981	981	981	981	981	981	1,437	1,437	1,437	1,477

Description	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Demand Response Programs (MW, Net of losses)	45	47	48	50	51	53	54	56	57	59
NMWEC	10	10	10	10	10	10	10	10	10	10
Red Mesa	5	5	5	5	5	5	5	5	5	5
Prosperity Battery Demo	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
Utility Scale Solar PV (20 MW - 2013 REPP)	11	11	11	11	11	11	11	10	10	10
Utility Scale Solar PV (23 MW - 2014 REPP)	16	15	15	15	15	15	15	15	15	15
Utility Scale Solar PV (40 MW - 2015 REPP)	30	30	30	30	29	29	29	29	28	28
PNM Sky Blue 1.5 MW Solar	1	1	1	1	1	1	1	1	1	1
Dale Burgett Geothermal Plant	1	1	5	7	7	7	7	7	7	7
100 MW Solar PV	-	-	-	-	-	-	-	-	35	35
50 MW Solar PV	-	-	-	-	-	-	-	18	18	18
Data Center 1 Solar PV - 20 MW	-	-	-	-	-	-	11	11	11	11
Data Center 1 Solar PV - 40 MW	-	-	-	-	-	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	-	-	-	23	23	23	23	23	23
Data Center 1 Solar PV - 30 MW	-	-	-	23	23	23	23	23	23	23
Data Center 1 Solar PV - 40 MW	-	-	30	30	30	30	30	30	30	30
Data Center 1 Solar PV - 30 MW	-	23	23	23	23	23	23	23	23	23
Data Center 1 Wind - 30 MW	-	-	-	-	-	1	2	2	2	2
Data Center 1 Wind - 50 MW	-	-	-	-	2	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	-	3	3	3	3	3	3	3
Data Center 1 Wind - 50 MW	-	-	3	3	3	3	3	3	3	3
50 MW Solar PV for RPS	-	-	7	18	17	17	17	17	17	17
NMWEC Repower for RPS	-	-	-	-	-	-	-	-	-	-
Total Renewable Resources (MW)	86	108	151	189	213	244	255	272	307	306
Total System Resources (MW)	2,363	2,235	2,279	2,318	2,344	2,377	2,348	2,367	2,403	2,444
Reserve Margin (MW)	492	335	353	357	344	344	296	296	310	330
Reserve Margin (%)	26.3%	17.6%	18.3%	18.2%	17.2%	16.9%	14.4%	14.3%	14.8%	15.6%

The retirement of PNM's coal resources also produces dramatic shifts in the energy fuel mix. Figure 51 shows how the portion of energy generation fueled by coal shifts to other resources over the planning period.

Figure 51. PNM Energy Mix



Transmission

The existing transmission system adequately meets the needs of current loads and resources. PNM considered projected changes to loads and resources for the future and identified two items that merit further study to address. These studies are included in the four-year action plan:

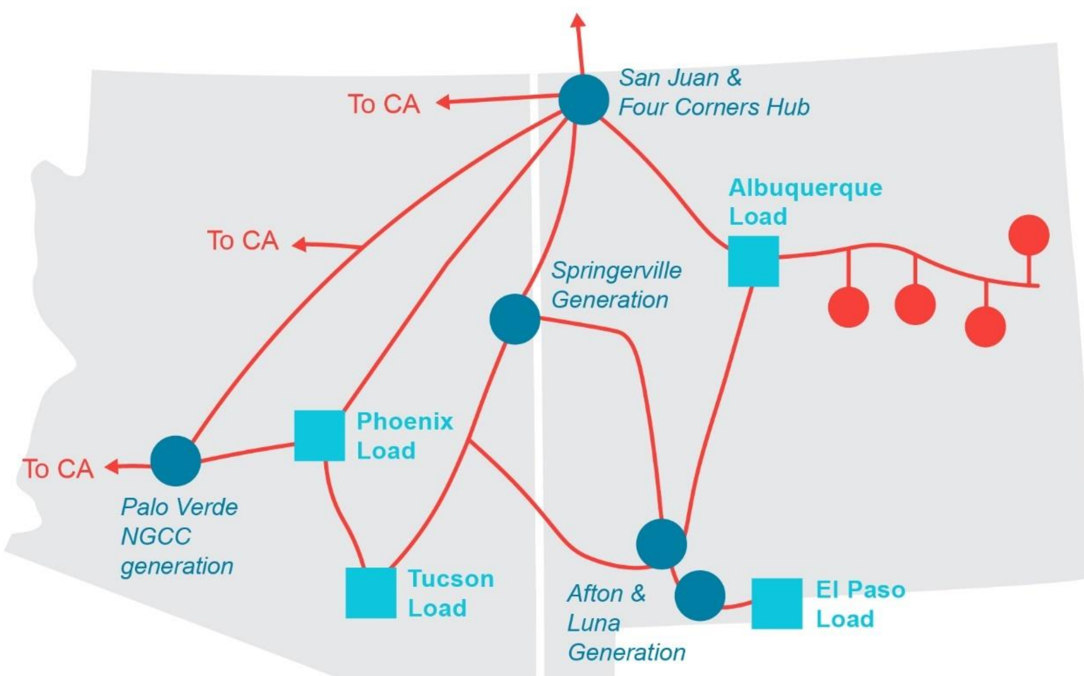
- Siting requirements for SJGS and FCPP replacement resources
- Additional transmission from eastern New Mexico is needed to support future wind energy supply to PNM's customers

Siting Requirements for SJGS and FCPP Replacement Resources

The effect of additional generating unit shut downs in the Four Corners area on operation of the transmission grid has not been studied beyond existing shutdowns of FCPP Units 1, 2 and 3 and SJGS Units 2 and 3. There would be a potential need to replace voltage control from the generating units with additional devices that can increase or reduce shunt reactive compensation in the area. It is likely that most control can be accomplished through use of new and existing switched shunt reactors or capacitors but significant frequent variation in loadings could also drive consideration of dynamic control like an Static Var Compensator (SVC). The existing transmission out of the Four Corner's area was optimized for transferring power to load centers in Arizona, California and New Mexico. Without the generation at the existing locations, it is likely that overall transfer capability of the system will be reduced below the historic transfer levels. Depending on the location and direction of future transfers on the existing transmission paths, there may be a need to modify or add series compensation or add flow control devices like a phase-shifting transformer to re-optimize the overall transfer capability of the system. Additional studies are needed to better define the voltage control requirements and limitations on transfer capability as a result of additional generating unit shutdowns in the area.

This IRP considered retiring SJGS in 2022 and the potential retirement of FCPP in 2031. PNM will need to replace the voltage support service provided by SJGS with other generation. Figure 52 shows how both the SJGS and FCPP sit between the Albuquerque/El Paso and Phoenix/Tucson load centers. If both plants are retired, reliable transmission system operations may require some form of voltage support at the Four Corners Hub. Additionally, new generation could benefit from the existing transmission facilities if it were located at SJGS. The overall PNM system will also benefit from a plant sited at the same location because of voltage support provided from that location. PNM will further study transmission system operational requirements associated with SJGS and FCPP retirements as part of the four-year action plan.

Figure 52. Transmission Network Map



Transmission Needed for Wind Resource Expansion

Because of weather conditions that result in consistent wind availability, New Mexico's best siting opportunity for wind resources is in eastern New Mexico. The existing transmission system includes a radial line from the BA switching station east of Albuquerque to the Blackwater HVDC converter station near Clovis, New Mexico. Pattern Energy Group, Inc. has developed the Broadview wind farm (297 MW) that interconnects to PNM's Blackwater station near the Texas border and plans to develop a second wind farm called Grady (200 MW) that will interconnect to their transmission line that is interconnected PNM's Blackwater station. Avangrid is developing the El Cabo wind farm (298 MW) that will interconnect to PNM's line near Clines Corners in June 2017.

The addition of these wind farms, along with the existing wind farms, will result in 1,000 MW of requested transmission service on the EIP line. As a result, PNM will be installing a voltage support device, a Static VAR Compensator (SVC), to the EIP line scheduled to be in service in March 2018 to accommodate these projects' transmission service needs. In addition, a synchronous condenser (i.e., essentially a generator without the turbine to provide synchronous current compensation) will be required at Blackwater station to offer the remaining of transmission service to the Grady windfarm. Table 45 shows transmission availability from Eastern New Mexico to Albuquerque.

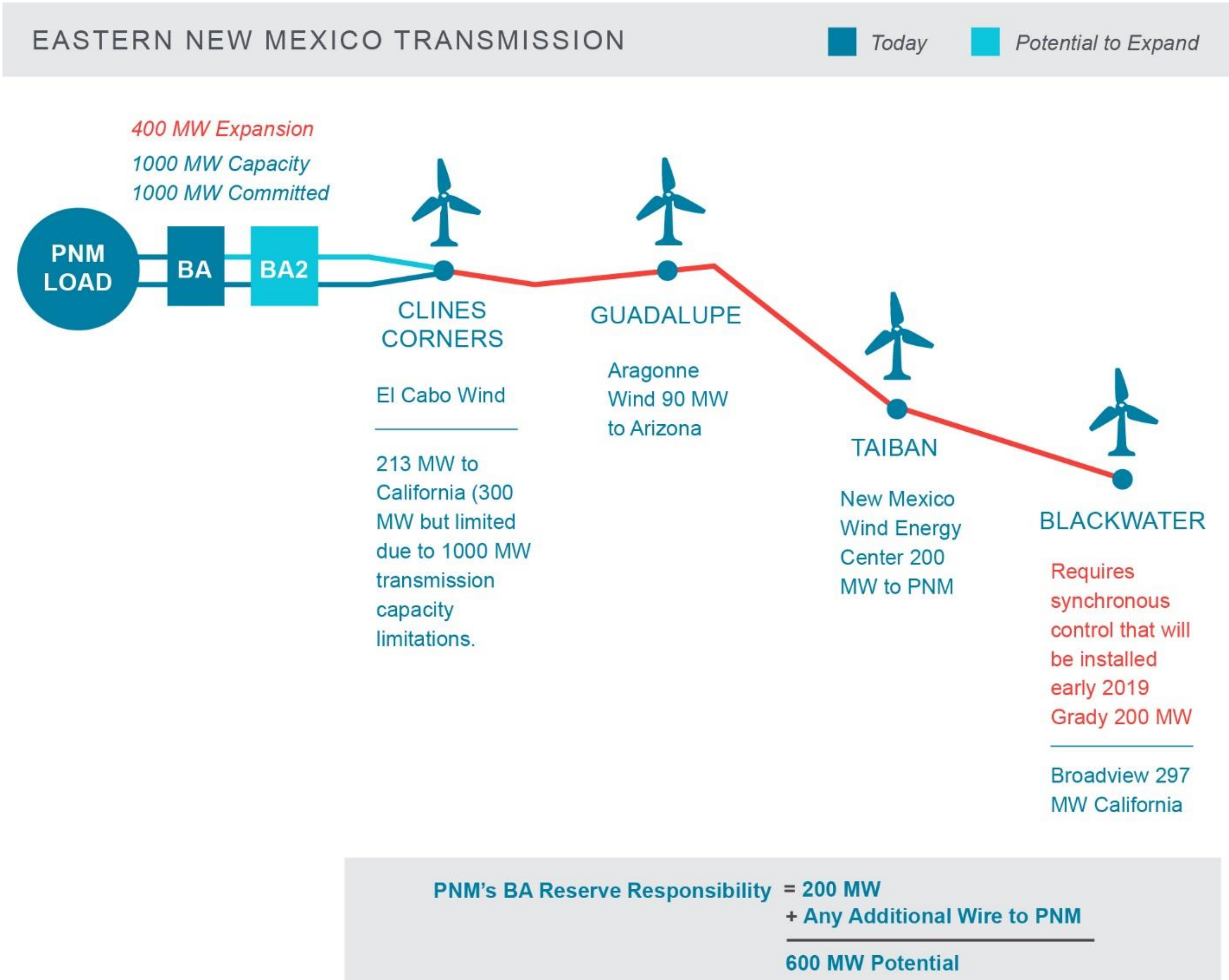
Table 45. Blackwater to Albuquerque Transmission Loads

Name	Size (MW)	Receiving Balancing Area
New Mexico Wind Energy Center	200	PNM
Broadview/Grady	497	California Independent System Operator
Aragonne Mesa	90	Arizona Public Service
El Cabo	213	California Independent System Operator
Total	**1,000**	

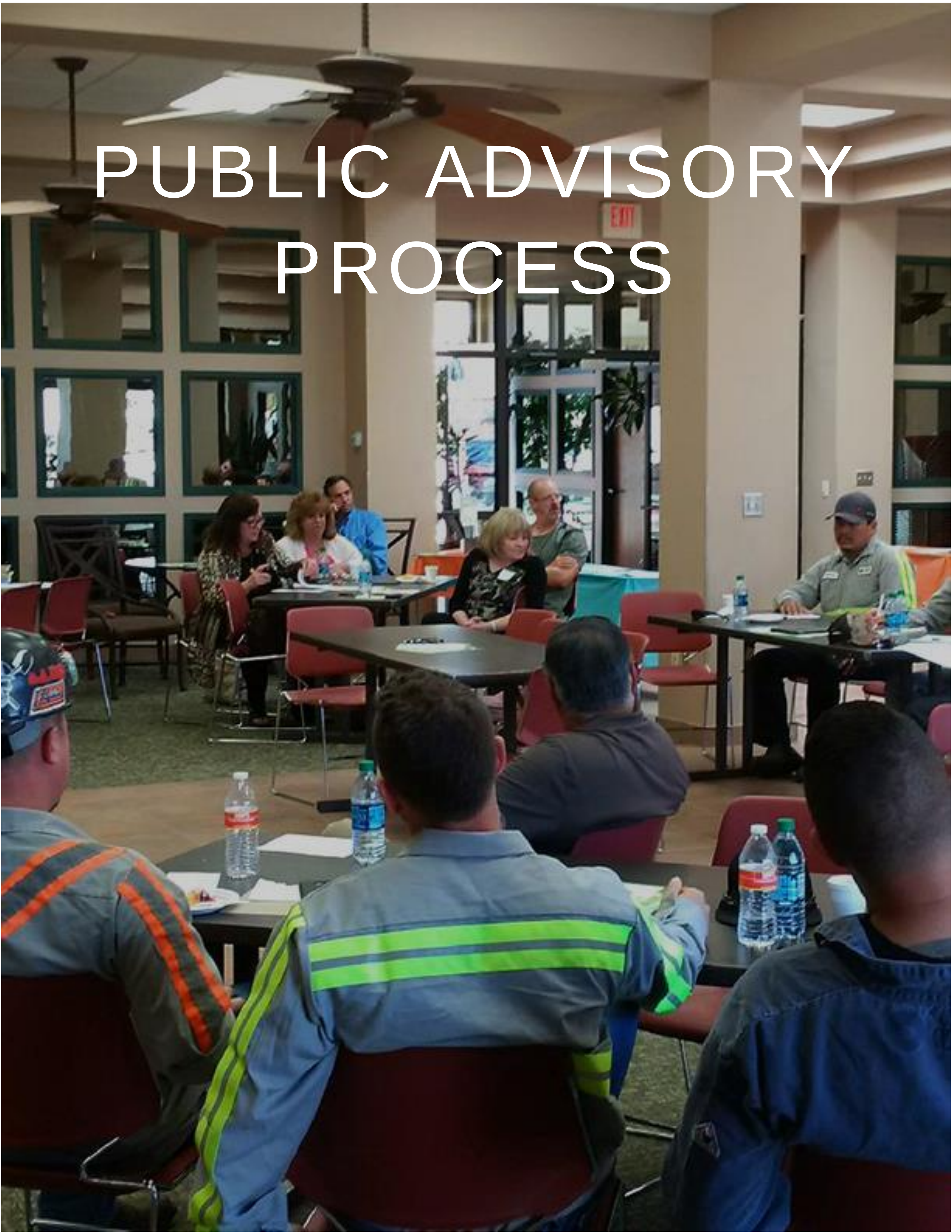
PNM characterized a potential transmission system resource of a 400 MW expansion of the eastern New Mexico transmission line to transmit an additional 400 MW of wind generation to PNM's customers as described in the Eastern New Mexico Transmission section above. A 400 MW expansion could provide sufficient wind generation to meet both PNM's RPS requirements and the currently projected data center requirement. The MCEP assumes the 400 MW expansion along with additional wind resources is sufficient to ensure future RPS compliance along with renewable energy to supply to the projected new data center.

Adding 400 MW of wind capacity to the eastern New Mexico transmission line affects PNM's reliability metrics because the largest single hazard would be 400 MW. Figure 53 is an illustration of the loads and resources connected to the Blackwater to Albuquerque line, with and without the expansion (BA2 and the additional line in light blue shows the expansion). If the new transmission line trips out of service, delivery of the power supplied on this line will be curtailed. Each balancing area must account for this possibility when assessing the need for planning reserves; PNM's current largest single hazard is SJGS Unit 4. Through the benefit of a hazard sharing agreement, this hazard is about 350 MW. If SJGS Unit 4 is retired, PNM's largest single hazard will fall to the Afton plant at 230 MW. Under an expanded transmission capacity and associated new wind generation, the largest single hazard would increase to 400 MW. The four-year action plan includes a feasibility study to identify the best option for PNM's customers.

Figure 53. Eastern New Mexico Transmission



PUBLIC ADVISORY PROCESS



PUBLIC ADVISORY PROCESS

PNM conducted a robust public advisory process as part of this IRP. The primary goal of the public advisory process is to solicit public comment and information to improve the overall process.

PNM placed newspaper advertisements and sent notifications in customer bills to create public awareness in the spring of 2016. On April 28, 2016, PNM notified the NMPRC and stakeholders in accordance with the IRP Rule. The public advisory process provides transparency of PNM's resource planning process and results by inviting public participation in community meetings. Representatives from the general public and various interest groups attended these meetings along with PNM staff. During these meetings, attendees actively engaged in the planning process by discussing the planning assumptions and approach, providing comments, sharing concerns, and by proposing alternative scenarios, assumptions, and methodologies for consideration.

After PNM issued the draft report, which showed the MCEP recommendation to retire or exit all coal generation in the portfolio, PNM scheduled a series of public comment sessions statewide to ensure broad opportunities for input. Hundreds of people attended these sessions.

Table 46 lists the IRP public advisory and public comment meetings, including dates and topics discussed.

Table 46. Topics of Public Advisory Meetings

Date	Topics
June 30, 2016	**IRP – Kick-off meeting** • Describe process and goals • Preliminary list of scenarios and sensitivities • Illustration of assessment of need for resources • Process for SJGS that includes IRP • Schedule • Establish communication
Jul 27, 2016	**Reliability Day** • Grid modernization • Advanced Metering Infrastructure • Batteries • Electric Vehicles • Demand response
Aug. 11, 2016	**Baseload Resources** • Coal SJGS FCPP • Palo Verde leases • Financial impacts • Asset recovery
Sept. 1, 2016	**Transmission and Generation Day** • Existing transmission • Projects PNM can model • Renewable energy • Energy efficiency
Sept. 22, 2016	**Fuel and Carbon** • Natural gas • Environmental regulation risks • Water issues
Nov. 10, 2016	**Load Forecast** • Rates and Tariffs
	Models Used **IRP Analysis Preliminary Plan**
Mar. 28, 2017	**IRP Process Update**
Apr. 18, 2017	**IRP Process Update**
Apr. 25, 2017	**Draft Report Discussion and Distribution**
May 23, 2017	**Advisory Group Comments**
July 5,, 2017	**Distribute Report and Wrap-up**

Public Advisory Meetings

At the meetings, PNM presented and discussed the data and analytic techniques used in this IRP and provided hard copy handouts of related reports and analyses to all meeting participants, encouraging an open discussion of the topics and related issues. The meetings were well attended by representatives of the NMPRC, other government entities, and other groups involved in utility regulation. Customers, renewable energy developers, advocacy groups, and interested citizens also took part. The meetings were broadcast as online webinars for those who could not attend in person. Meeting presentation materials for each meeting were posted on the IRP website.

The public advisory process resulted in significant contributions to PNM's planning process, with participants providing substantial feedback including prioritization recommendations regarding what areas had been covered adequately and which required more analysis. The following list provides examples of how PNM has responded to public comments in this process:

- This report includes a discussion of how resource planning affects PNM's business
- PNM provided information explaining why it is not considering replacing coal with natural gas as a fuel supply to SJGS
- The alternate portfolios considered includes higher levels of renewable supply than included in the MCEP
- PNM assessed the near-term and long-term potential of batteries other storage technologies to transform the market

Some advisory group participants requested data so that they could perform independent analysis. PNM provided data files on hourly customer load and hourly renewable energy production. There was also interest in PNM's solar-battery demonstration project, the Prosperity Solar-Battery Project. PNM provided solar and battery performance at one-minute and five-minute intervals in response. PNM has also made modeling data, assumptions, and outputs available. Participants were very interested in the key question of continuing vs. retiring SJGS in 2022, including these topics:

- The impacts of resource planning decisions on customers and local economies
- Environmental impacts of the decisions made
- Advanced technology and its potential to address resource planning challenges
- In particular, the potential for energy storage (specifically batteries) to reduce the electric system's dependence on fossil fuels

PNM delivered the initial findings of the analysis and the preliminary MCEP early in the process to allow time for review and feedback by participants and other stakeholders. PNM posted its preliminary draft report on April 20, 2017.

Public Comment Meetings

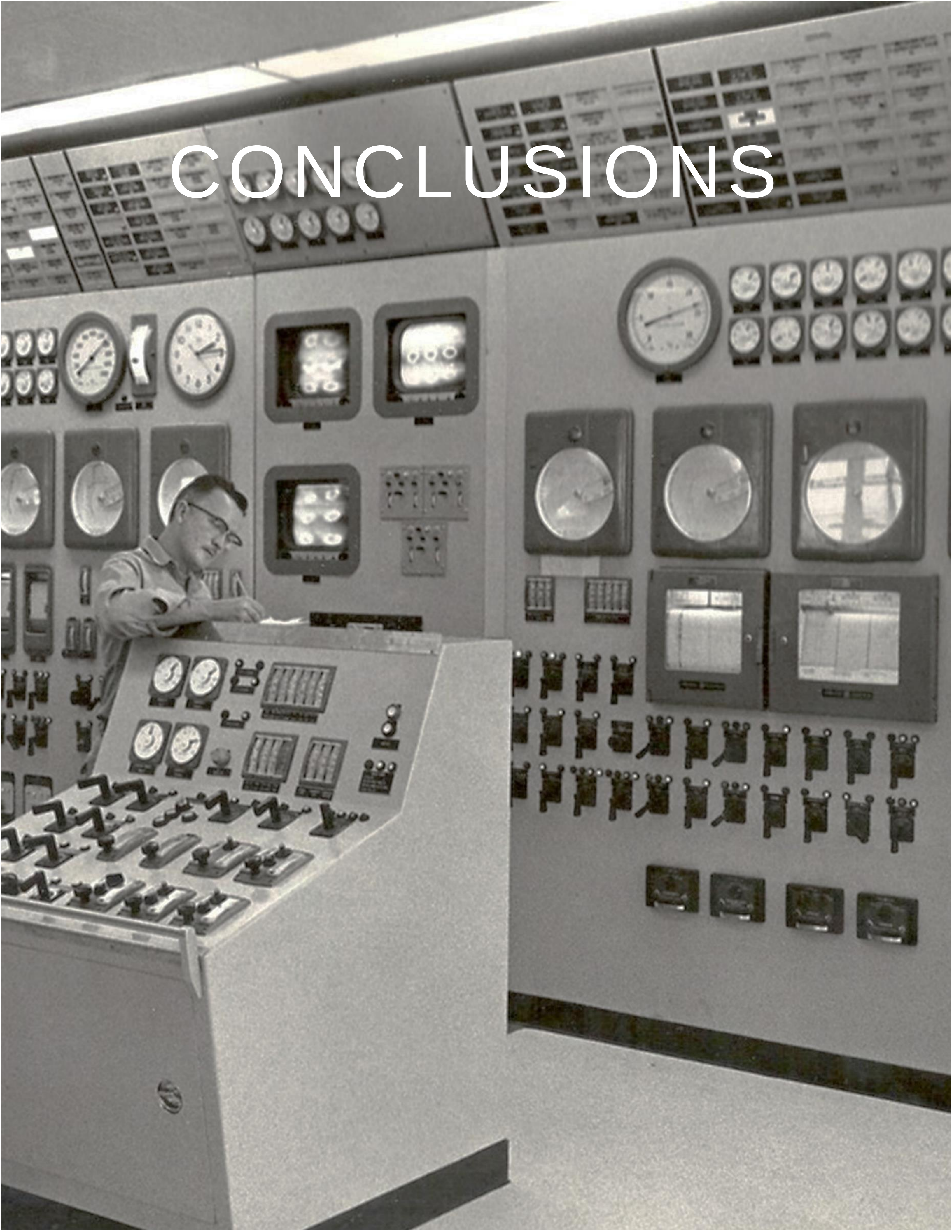
In addition to the Public Advisory meetings, PNM hosted public comment sessions statewide during the month of May, 2017. Table 47 estimates the number of attendees at each meeting based on sign in sheets. At each meeting, PNM provided all attendees an opportunity to speak their minds, and PNM heard a wide variety of opinions. The statements related to how PNM conducts an IRP analysis, comments on how the report can be improved, and comments about individual resources within the resource portfolio. In addition to these comments, PNM heard comments on topics that are not addressed in the IRP rule, including comments on the economic impacts associated with retirement of SJGS.

Both the public advisory meetings and the public comment sessions have improved the process and this report documenting the process.

Table 47. 2017 Draft Report Public Comment Meeting Attendees

City	Date	Location	Attendees
Farmington	May 10	San Juan Community College	439
Alamogordo	May 16	First National Bank	25
Deming	May 17	La Fonda Restaurant	29
Silver City	May 18	Grant County Business & Conference Center	44
Albuquerque	May 23	Albuquerque Museum of Art & History	71
Santa Fe	May 24	Federal Courthouse Park	69

CONCLUSIONS



CONCLUSIONS

This section provides a description of the MCEP and alternative plans to meet PNM's customer requirements from 2018 through 2036.

Most Cost-Effective Portfolio

The MCEP analysis for this IRP supports the following actions:

Before 2022

- Conduct an RFP, including battery storage, to confirm the modeling assumptions and analysis for the MCEP.
- Continue implementation of energy efficiency and load management programs to meet EUEA targets.
- Add renewable resources by 2020 for compliance with the Renewable Portfolio Standard.

2022 through 2025

- Pursue retirement of PNM's remaining capacity at SJGS in 2022 after the expiration of the existing coal supply agreement.
- Replace the retired SJGS with a mix of renewable energy resources, quick-start natural gas peaking capacity, and potentially energy storage.
- Retain the currently leased capacity in PVNGS before the leases expire in 2023 and 2024.
- Build a new transmission line to access wind energy from eastern New Mexico.

After 2022

- Maintain system reserves as load grows with renewable energy, gas peaking and/or energy storage additions.
- Plan to replace the capacity provided by Valencia when the Valencia PPA expires in 2028.
- Pursue abandonment of PNM's capacity at the FCPP at the expiration of the current fuel supply agreement in 2031 and plan, in future IRPs, determine the best mix of resources to replace the energy and capacity provided by the FCPP.

A portfolio of renewables, gas generation, and, potentially storage, provides the best balance of cost and reliability and results in a significant reduction in the environmental impact associated with supplying energy over the twenty-year planning period. Under the MCEP, PNM would cease coal generation 2031, and by 2025, increase to 32.6% the share of PNM's total load supplied by renewable energy. Carbon-free resources would supply two thirds of customers' energy needs by 2035. Figure 54, Figure 55 and

Figure 56 show the proportions of energy served by different fuel sources in 2017, 2025, and 2035.

Figure 54. 2017 MCEP Energy Shares

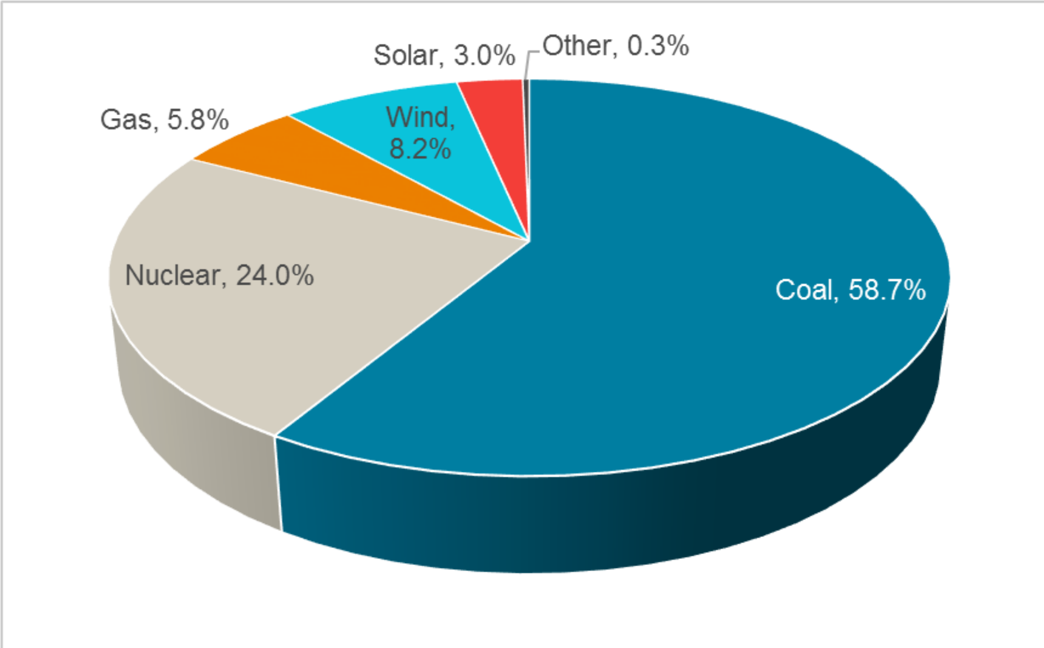


Figure 55. 2025 MCEP Energy Shares

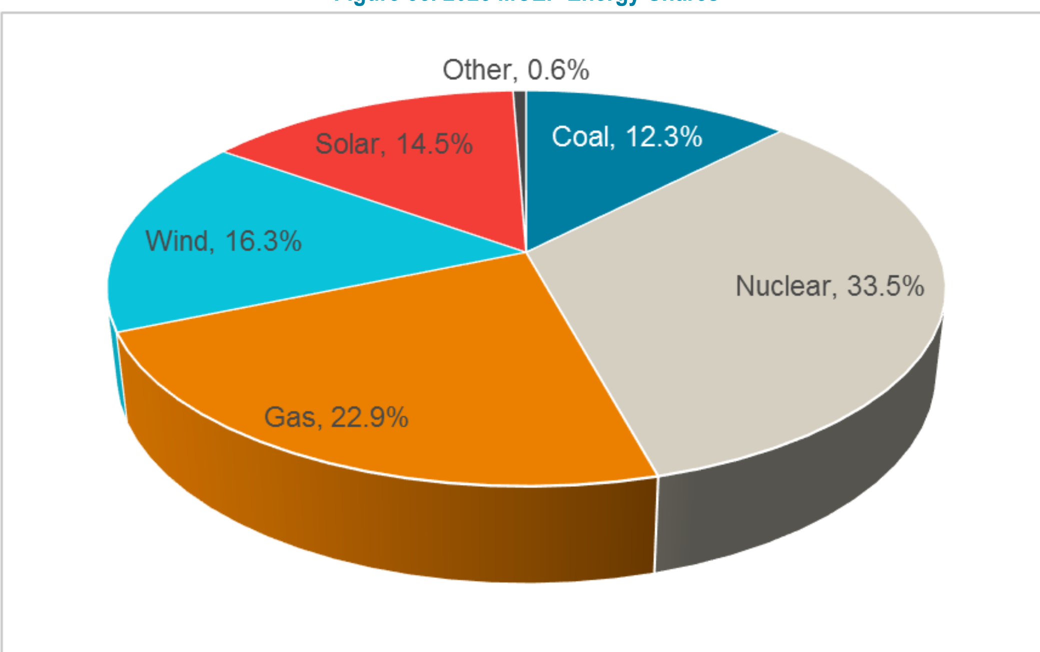
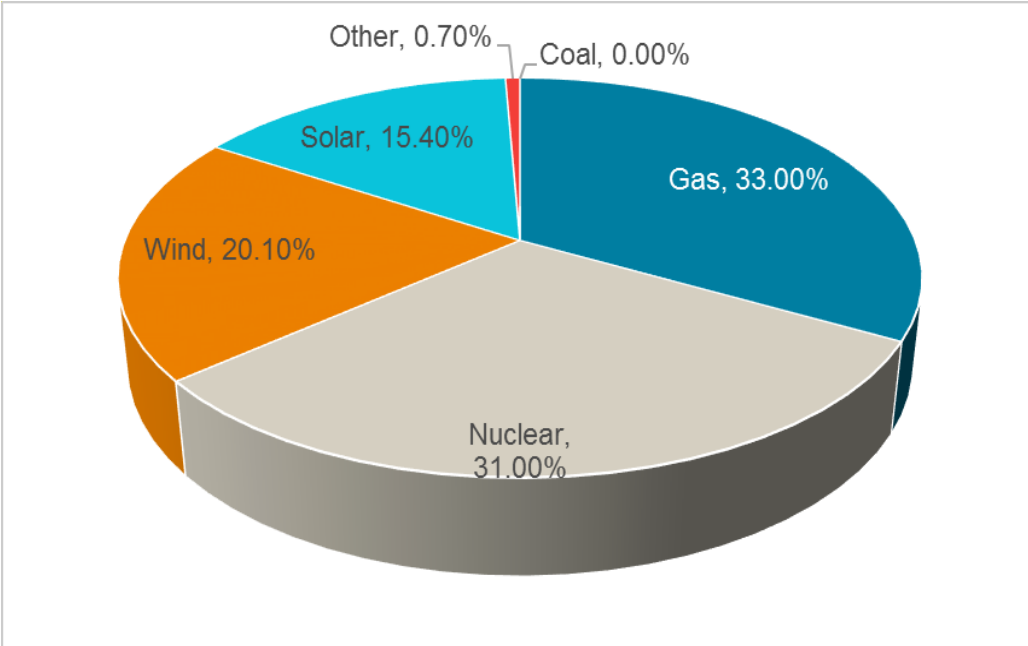


Figure 56. 2035 MCEP Energy Shares



This portfolio is the most cost-effective because it maintains a reasonable reliability expectation while achieving the following:

- Low projected customer cost and cost risk profile across most scenarios
- Lowest carbon emission profile
- Elimination of coal generation in 2031
- Lowest freshwater use

The MCEP achieves low customer cost through the replacement of base load resources with resources having lower operating costs and greater flexibility to produce energy that better matches projected customers' future energy use. The elimination of coal generation reduces environmental impacts while protecting against cost risk associated with known or reasonably anticipated environmental regulations. A load and resource table showing the MCEP resource additions and retirements by year is provided in Appendix N.

Key Conditions and Trends Shaping the Findings

PNM has concluded that a closure of SJGS in 2022 will be cost-effective for PNM customers. PNM concluded that closing all units in 2017 would not be cost-effective in 2017. These conclusions are not inconsistent. They results from the difference in the time-periods being studied and from changed conditions. In the last IRP, PNM was examining SJGS unit retirements as an approach to comply with Regional Haze Rule requirements at SJGS. The 2014 IRP recommended a compliance plan that had been approved by the EPA and the State of New Mexico in its MCEP. This plan included the retirements of SJGS Units 2 and 3 that will occur by the end of 2017 and showed this to be a better plan than retiring all four units of the plant. This IRP looks forward from the retirements that will occur at the end of 2018 and examines retirement of the remaining two units over a different 20 year planning horizon.

Retiring all four units of SJGS in the 2014 IRP to comply with the regional haze rule required considering replacing 783 MW of capacity in four years. This IRP assumes the retirement of 286 MW at the end of 2017 and examines retiring the remaining 497 MW in five years. In addition to the analysis being fundamentally different, several other key assumptions have changed since PNM's last IRP.

One such changed condition is a significant reduction in anticipated natural gas-fired generating costs. Natural gas prices have declined steadily over the past decade, largely as a result of advances in drilling technology, but also with development of additional pipeline delivery capacity and gas storage. Also, gas generating equipment costs and efficiency have improved. Gas prices in future years are forecasted to be lower than previously forecasted. As a result, the costs to replace SJGS are lower, since that capacity can be replaced with now low cost gas-fired peaking resources.

Another changing factor is the increased renewable energy planned for PNM's system to meet the NM renewable portfolio standard requirements and as a result of growth in the amount of renewable resources added by and for customers. Some new large customers wish to offset their energy use with the addition of renewable sources. PNM's system is now expected to supply about 30% of its retail energy sales using renewable resources by 2023 when SJGS is retired. This IRP report explains that renewable energy is generally a must-take type of energy in a utility's dispatch selection order, therefore it will replace generation from baseload resources during many hours throughout the year.

Another important change is that PNM's load growth forecast is lower than previous forecasts. This reflects the poor performance of the NM economy over the past decade as well as changes in the level of electricity use by several large PNM customers. Energy efficiency and demand response investments have also contributed to a reduction in energy consumption. The reduced level of forecasted energy use means SJGS is now less critical than before to meet long-term energy needs.

PNM operates in a unified electric grid that covers most of the western U.S. and parts of Canada and Mexico. As a result, trends in the region affect PNM. Nearby states such as California and Arizona have, like New Mexico, experienced an increase in intermittent renewable generation that, in turn, has increased the need for flexible generation, such as natural gas generation, to follow the intermittency in the output of the renewables. Consequently, PNM is unable to rely on inter-utility energy purchases and sales for system balancing to the extent it has in the past.

Alternate Portfolios

In addition to the MCEP, the following alternate portfolios also would supply energy and capacity with a reasonable reliability expectation. However, based on current cost assumptions, these portfolios are more costly for customers and carry a higher cost-risk profile due to the impact of increases in natural gas prices and potential environmental regulations

Continue Coal Baseload Alternative

The top ranked portfolio that continues SJGS through the planning period includes the following resource additions and retirements:

Before 2022

- Continue implementation of energy efficiency and load management programs to meet EUEA targets.
- Add renewable resources by 2020 for compliance with the Renewable Portfolio Standard.

2022 and Beyond

- Build a new transmission line to access wind energy from eastern New Mexico.
- Maintain system reserves as load grows with renewable energy and gas peaking or energy storage additions.
- Plan to replace the capacity provided by Valencia when the Valencia PPA expires in 2028.
- Pursue abandonment of PNM's capacity at the FCPP at the expiration of the current fuel supply agreement in 2031 and plan in future IRPs to replace the energy and capacity provided by the FCPP.

The MCEP is preferred over this portfolio because it replaces SJGS base-load capacity with the more flexible generation needed to match projected customer use. In addition, there will be less need for traditional baseload generation and greater need for more flexible resources as PNM and its customers add more intermittent renewable energy to the system. Continuing to operate SJGS also subjects PNM customers to risks of higher costs associated with future environmental regulations affecting coal-fueled generation.

Higher than 50% Renewable Energy Use

PNM examined a portfolio that would increase renewable energy use to nearly 50% of total energy supplied by 2025. However, this portfolio is more costly, would not avoid adding a similar quantity of gas peaking resources as in the MCEP, and would require a significant increase in load following and system flexibility as described in the reliability analysis, with renewable energy curtailments becoming a common, low cost reliability management option.

These observations are driven by the need to maintain reliability at reasonable levels considering currently available storage technology. As technology changes, PNM will revisit this portfolio in future IRPs to reassess whether renewable energy use in excess of 50% of energy supplied is cost-effective.

PVNGS-Leased Capacity

In the portfolio analysis, PNM treated the existing leased capacity at PVNGS as a resource available for purchase upon lease expiration. The IRP analysis found that retaining the leased capacity is favorable because of its high reliability, no air emissions, and the hedge it provides against natural gas price increases. If PNM did not retain the leased capacity, the following changes to the MCEP would occur:

- Procure a low heat rate natural gas combined cycle generation facility to replace PVNGS energy
- A 9% increase in CO_2 emissions over the planning period
- A 30% increase in the cost risk range calculated in the Monte Carlo analysis because of natural gas cost volatility
- Ongoing financial obligations associated with this resource continue.

Retaining the PVNGS-leased capacity does not preclude pursuit of a portfolio with renewable energy resource supplying over 50% of energy. However, the same technology improvement required to efficiently operate the "Higher than 50% Renewable Use" portfolio would also be needed if PNM abandons the PVNGS-leased capacity.

Four-Year Action Plan

The twenty year planning period for this IRP can be viewed in three phases corresponding to the coal plant retirements in the MCEP. From 2017 to 2022, resource additions will occur as a result of energy efficiency and load management filings, renewable procurement plan filings and renewable energy additions associated with the data center customer. A SJGS retirement in 2022 begins a second phase, from 2022 through 2031, when PNM will be replacing SJGS with a mixture of natural gas peaking capacity, renewable energy and, potentially, energy storage. Sufficient firm capacity will be needed to replace SJGS retired capacity to meet summer peak needs in 2023. In addition, during this phase, PNM will be replacing the capacity associated with the Valencia PPA and retain the nuclear capacity associated with the leases at PVNGS. In the third phase beginning 2031, PNM will be addressing system needs associated with the potential Four Corners retirement. The actions PNM will need to complete in the next four years to address these events are:

- Energy Efficiency and Load Management filings at the frequency required by the Energy Efficiency Rule
- Annual renewable energy procurement plan filings required by the Renewable Energy Act and Rule 572
- CCN or PPA approvals for renewable energy resources associated with the data center customer
- Pursue SJGS abandonment
- Identify, procure and seek approval for replacement resources for SJGS
- Retain the Palo Verde leased capacity
- Complete the 2020 Integrated Resource Plan to address the resource planning implications of the Valencia PPA and Four Corners retirements

PNM will pursue several actions associated with the SJGS abandonment. The next step will be issuing an all-source request for proposals. The intent of the RFP is to refine the mix of replacement resource types identified in this IRP (natural gas peaking, renewable energy and, potentially, energy storage) to specific projects that could be proposed for NMPRC approval in later filings. Bidders will be free to submit bids for any type and size of resource at any proposed location.

However, because the location and combination of replacement resources can affect system reliability, as indicated in the IRP, PNM's RFP will also request bids for resources to be located at specific sites and for specific resource combinations. For example, the significant permitting and transmission interconnection work that has been completed at the La Luz site makes this a logical location for additional gas peaking and energy storage resources, so combinations of peaking and storage bids may be requested at La Luz. The RFP will also request bids at SJGS. PNM will make its final determination on the scope and content of the RFP after discussion with the parties to Case No. 13-00390-UT as required by the final order in that case.

Upon receipt of all bids (including those requested by PNM and any other credible proposals), PNM will repeat the capacity expansion, economic dispatch and reliability analyses performed for this IRP to identify the best combination of resources and locations from the alternatives presented. This work will be completed in advance of PNM making the filing required by the final order in Case No. 13-00390-UT on the extent to which SJGS should continue serving PNM's retail customers' needs after June 30, 2022. The specific steps in the process to pursue SJGS abandonment are:

- Consult signatories to Case 13-00390-UT on the scope and form of the RFP
- Invite stakeholders to a public advisory discussion on energy storage options
- Issue all-source request for proposals that will include invitations to bid specific sites and technology combinations
- Evaluate bids to build a portfolio of specific replacement resources for SJGS replacement
- Make filing with the NMPRC on the extent to which SJGS should continue serving PNM's retail customers after June 30, 2022

It is expected that the SJGS filing will identify the steps PNM will follow in requesting abandonment authority and replacement capacity approval from the NMPRC. The four-year plan for the 2017 IRP is detailed in Table 48. In addition to the SJGS abandonment actions identified above, the table identifies actions to implement the MCEP, which include monitoring technologies that could enable PNM to cost-effectively increase its use of renewable resources to more than 50% of its energy production.

Table 48. MCEP Four-Year Action Plan

Task	Action	Timing
Energy efficiency and load management	File plans to continue energy efficiency and load management programs in accordance with NMPRC Rules	File a plan at least every three years (most recent application was filed in April 2017)
2020 RPS compliance	Procure resources to maintain compliance with RPS when standard increases from 15% to 20% in 2020	2017 RFP, request resources in 2018 Renewable Procurement Plan filing
Data Center renewable energy additions	Request CCNs or PPAs to support renewable energy associated with data center customer load growth	As required to meet increasing energy consumption at the data center
Explore options for system supply and reliability	Assess costs and benefits of joining the California EIM	Begin study in 2017, future action depends on study results
	Assess cost to maintain Reeves Generating Station and develop plan to maintain voltage support at Reeves long term	Study cost to maintain Reeves in 2017, assess reliability requirements and long term investment strategy in context of need for SJGS replacement capacity
	Participate in regional transmission planning groups	Ongoing
Pursue abandonment of SJGS in 2022	Consult Case No. 13-00390-UT Stipulation Signatories	July or August 2017
	Energy Storage Public Advisory discussion	July or August 2017
	Issue All Source RFP	Q4 2017
	Analyze proposals to refine SJGS replacement portfolio	Q2 2017
	File report with NMPRC on the extent to which SJGS should continue serving PNM's retail customers' needs after June 30, 2022	Between July 1, 2018 and December 31, 2018
Retain PVNGS Leased Capacity	Ascertain ability to re-purchase leases in advance of re-purchase process defined by the terms of the leases	Complete by end of 2017
New transmission capacity for wind from eastern New Mexico	Assess potential for development or participation in transmission system expansion	Begin process in 2017
2020-2040 Integrated Resource Plan	Conduct IRP analysis per rule, including assessments of Valencia PPA and Four Corners, develop MCEP and Four-Year Action Plan	Kick off in June 2019