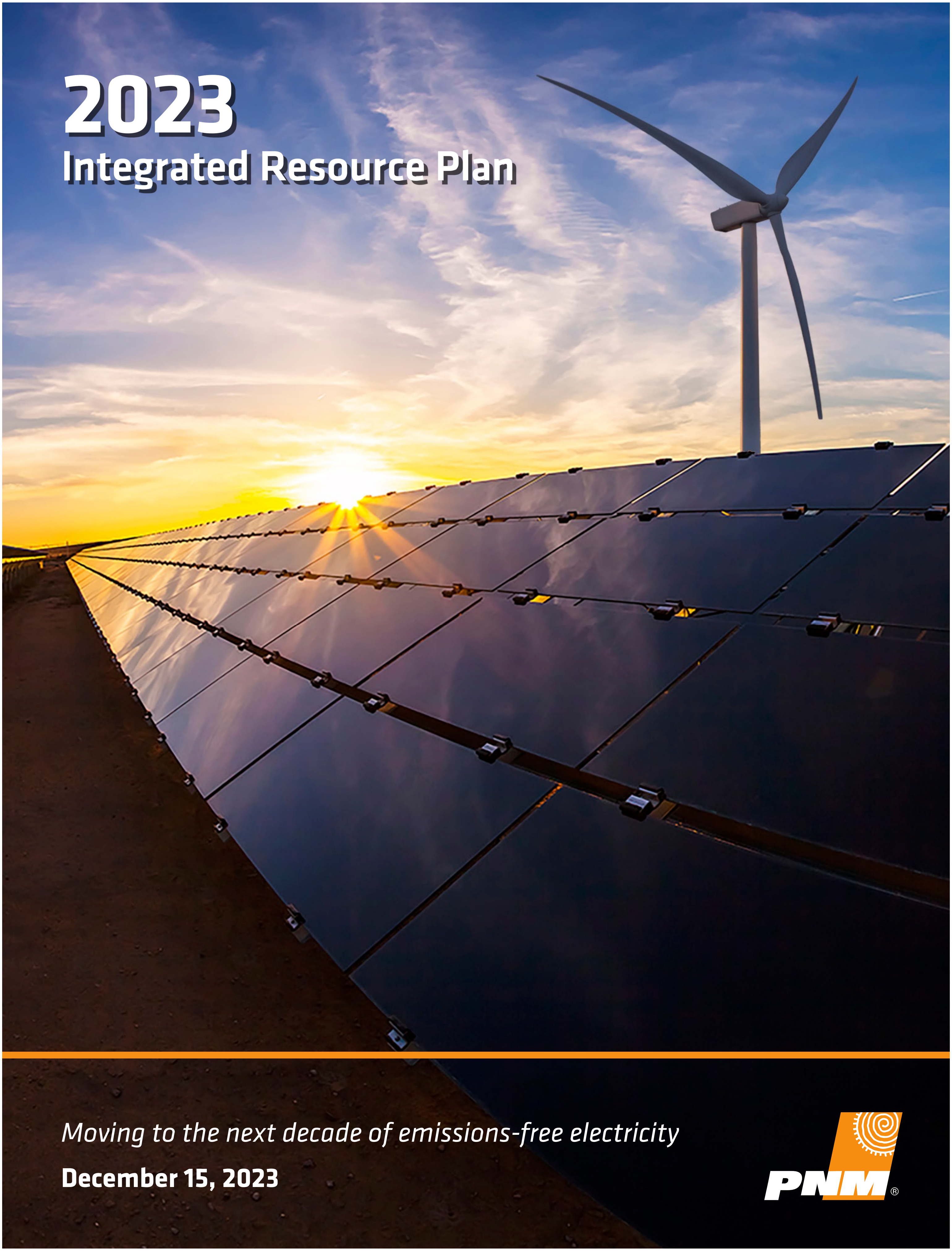
2023
Integrated Resource Plan



Moving to the next decade of emissions-free electricity

December 15, 2023

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.

Acknowledgements

PNM appreciates the organizations and individuals that contributed to the 2023 Integrated Resource Planning process. The PNM team thanks each of you for your time and for lending your expertise to move New Mexico forward on the pathway to decarbonization. Insights from these team members contributed to creating a more robust Integrated Resource Plan:

- First and foremost, the **Public Advisory Group** spent countless hours at Public Advisory Meetings and Facilitated Stakeholder Meetings learning about this process and providing input to help shape the IRP's Statement of Need and Three-Year Action Plan.
- **Gridworks** professionally let the Facilitated Stakeholder Process to help solicit input and comments on PNM's development of the Statement of Need and Three-Year Action Plan.
- **Energy and Environmental Economics, Inc. (E3)** provided invaluable guidance in the development of the IRP through their work throughout the Western US.
- **Astrapé Consulting** provided expertise and coordination in reliability modeling.
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- **Applied Energy Group**, **PACE Global, Aion Energy** and **Itron** contributed to the development of the Energy Efficiency, Commodities, Resource Technology Cost, and Load Forecasts.
- **Sandia National Laboratory** provided guest presentations to the Public Advisory Group and continued support through our Collaborative Research and Development Agreement (CRADA).
- Finally, I would personally like to thank **Nick Phillips** for his hard work and leadership throughout this process!

To move toward an even more integrated planning approach, PNM recently combined its Integrated Resource Planning team with the Transmission Planning and Engineering teams to expand consideration of solutions across the generation, transmission, and distribution segments. Integrated Systems Planning is critical to an efficient and cost-effective realization of a clean energy future. I am proud to continue the great progress Nick and the IRP team have made toward a sustainable energy future and look forward to ongoing collaboration with this team.

Realizing a carbon-free grid is the challenge of our time and it requires collective efforts to solve. Thank you again for your contributions and I look forward to completing the 2023 IRP Action Plan and beginning work towards the 2026 IRP.

Thank you,

Laurie Williams
Executive Director, Integrated Systems Planning

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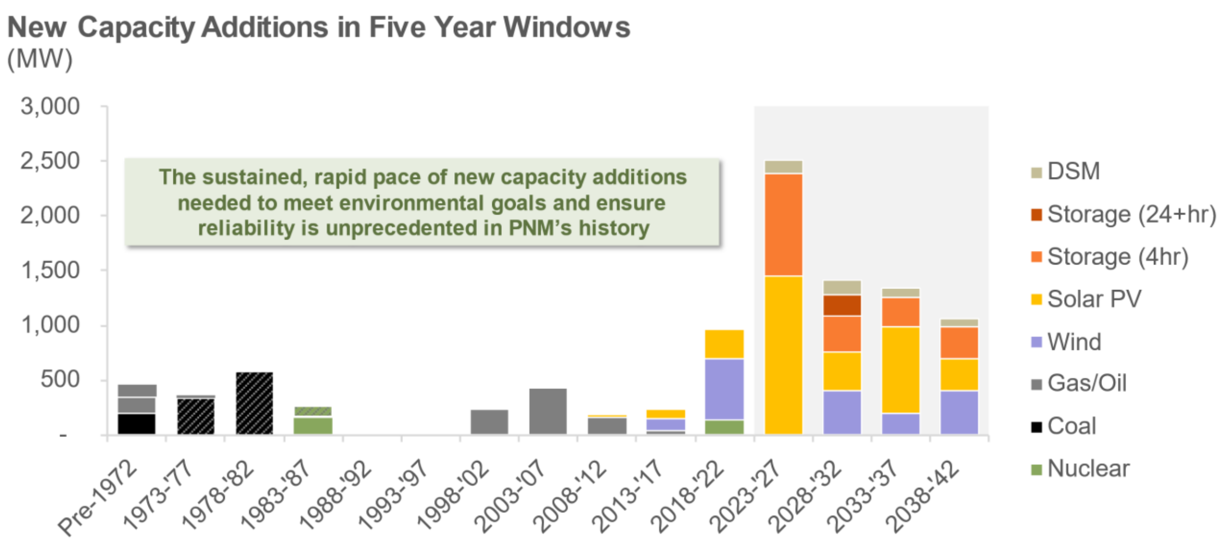
Executive Summary

Public Service Company of New Mexico's (PNM) 2023 IRP lays out an aggressive plan to achieve a carbon-free portfolio by 2040. PNM's last IRP was filed with the New Mexico Public Regulation Commission (NMPRC) in early 2021, shortly after PNM established a goal to transition to a carbon-free energy system by 2040. Three years later, PNM remains firmly committed to its long-term goal to transition to a carbon-free system. In the intervening years, PNM has built confidence in this vision, gaining experience operating new technologies and retiring the last two units of the San Juan Generating Station (SJGS), the largest, most carbon-intensive power plant in the portfolio. The Inflation Reduction Act was also passed in this period, providing billions of dollars of federal tax benefits and loan guarantees to support development of clean energy infrastructure.

Each passing year brings PNM closer to decarbonization, and each IRP provides an opportunity to refine plans to capture opportunities, and meet the challenges ahead, as the future comes into sharper focus. Over the next eight years, PNM's portfolio is poised to undergo a significant transformation. Between the expiration of the power purchase agreement with Valencia, planned exit from Four Corners Power Plant (FCPP), and the end of the depreciable life of Reeves Generating Station, the resource portfolio stands to lose over 500 MW of firm generating capability, representing one quarter of present peak demand.

Replacing retiring or expiring capacity, meeting concurrent load growth, and reducing the carbon intensity of PNM's portfolio will require significant sustained addition of resources over the next two decades. The scale of this transformation is unprecedented in PNM's history and will challenge the company's ability to plan, coordinate, and execute. For this IRP, PNM developed a robust plan to meet resource needs and decarbonize the portfolio by 2040. Figure 1 shows the new capacity resources included in the **Most Cost-Effective Portfolio (MCEP)**, contextualized against the historical additions to the portfolio over the past six decades.

Figure 1. Historical and projected capacity additions in the Most Cost-Effective Portfolio



Timing of resource additions based on date each plant entered PNM's portfolio. DSM data included beginning in 2008. Bars with hashed lines indicate resources no longer in PNM's portfolio. Future hydrogen resources may operate using natural gas fuel until PNM transitions to a fully carbon-free portfolio in 2040.

The technologies needed to meet customers' demand while moving towards a carbon-free portfolio include three general categories of resources:

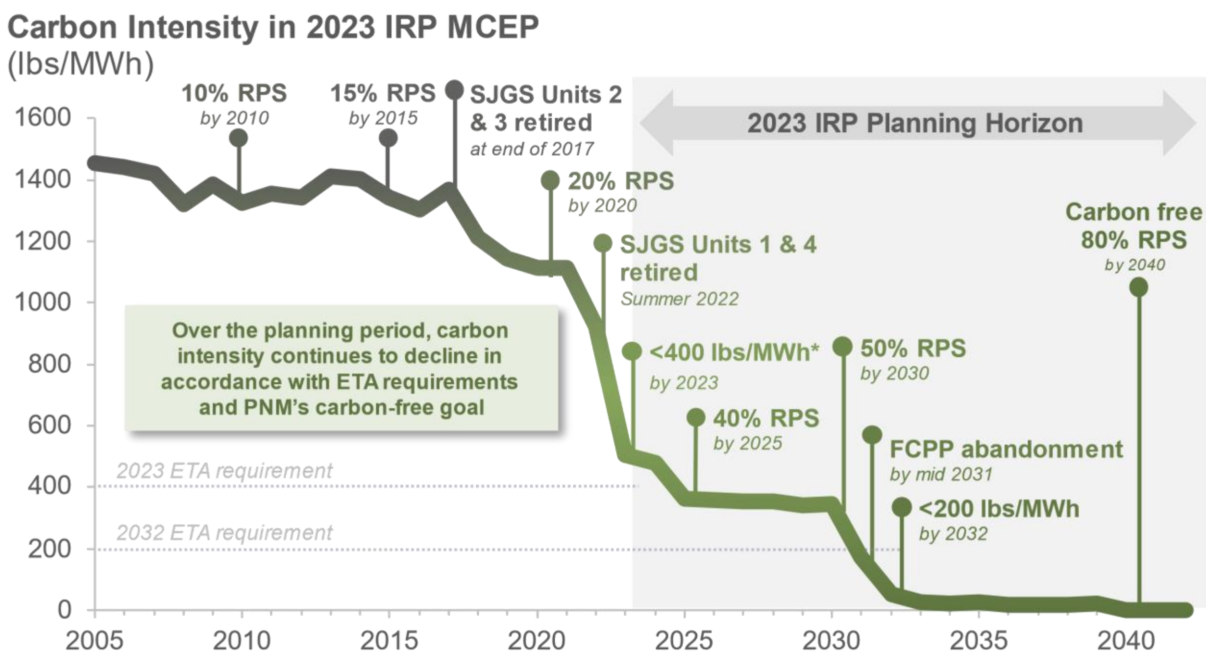
Low-cost carbon-free energy resources produce clean energy to meet a majority of customers' energy needs throughout the year. In 2019, PNM's energy mix was roughly 44% carbon free. With the replacement of SJGS, this figure will increase to approximately 65% by the end of 2023. Meeting the 100% carbon-free goal by 2040 requires investment in resources able to generate carbon-free energy like solar PV, wind, and energy efficiency.

Dynamic balancing resources provide PNM with tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of the carbon-free resources will not coincide naturally with electricity demand. Examples include shorter-duration energy storage and demand response.

Firm generating resources operate at or near full capacity for extended periods of time that will allow PNM to maintain reliability even under the most constrained conditions in the system, which may include both periods of high demand as well as periods of low output from renewable resources. Today, these needs are met with nuclear and fossil resources; in the future, various emerging technologies including hydrogen and long-duration storage may also be options.

Together, the portfolio of resources in the MCEP enables continued carbon reductions and increasing renewable energy supplies to comply with the Energy Transition Act (ETA) and PNM's own goals. Figure 2 shows the carbon intensity of PNM's planned portfolio over the IRP horizon in the MCEP.

Figure 2. Carbon intensity over time under PNM's proposed MCEP



Reported carbon intensity is calculated from modeling results by dividing total emissions from PNM internal generation by total annual energy requirements. Actual outcomes may vary depending on final rules adopted by the NMPRC. Delays of replacement resources for SJGS and PVNGS may also have an impact on PNM's ability to meet ETA carbon intensity requirements in 2023 and 2024.

An Industry in Transition

As in 2020, this 2023 IRP was developed against an industry landscape which continues to rapidly evolve. The most important development in the industry in recent years has been the passage of the **Inflation Reduction Act (IRA)**, which is transformative federal legislation authorizing billions of dollars of support to encourage development of new clean energy resources. With broadly defined tax credits and loan guarantees for clean energy assured through the next decade, the industry can move forward with expanding and bolstering available clean energy incentive programs, proven resources, including wind and solar, will continue to be developed, while emerging technologies, like long-duration storage and hydrogen fuel, will mature. This progress allows for clean resources to be available when PNM needs them in the future. The clarity and opportunity that this legislation brings to the energy industry is critical to achieving ambitious clean energy goals.

The optimism that accompanied the passage of the IRA has been moderated by real-world challenges encountered by utilities and project developers over the past several years. Costs for new infrastructure projects are rising – driven by a combination of global supply chain disruptions and increasing lead times, inflation and rising costs due to significant increased demand for equipment and materials in the electric industry and rising interest rates – resulting in a reversal of previously steady downward trends in the costs of wind, solar, and energy storage. These changes have also impacted development timelines for projects already under development – and in some cases, threatened in-services dates and even project viability altogether. PNM has experienced the effects of these disruptive forces firsthand with the delays and cancellation of replacement resources for SJGS, which resulted in an extension to the operating lifetime of Unit 4 through the summer of 2022 and market purchases required to ensure service continuity.

In the face of these challenges, PNM remains committed to the vision for a reliable, affordable, and carbon-free power supply by 2040. Therefore, this IRP is focused on the opportunities ahead but remains cognizant of the risks and ensuring proper protection of customer reliability and system resilience. Urgent action is required, as many of the viable options require years of lead time and preparation to successfully integrate into PNM's portfolio. Permitting and development timelines require years to complete, and in recent years, have stretched beyond historical norms. This means that the 2030 system must be planned and developed today. Achieving the goals of a reliable, sustainable, and affordable portfolio requires proactive planning and sustained action.

In an environment that can change suddenly and unexpectedly, PNM seeks to create a plan that is flexible and adaptive; the value of a comprehensive planning framework lies in the shape of that plan and the playbook it provides for how to adjust the plan and when needed as a result the evolving industry environment and conditions.

Updates to the IRP Rule

The IRP Rule, set forth by the NMPRC, establishes requirements for the resource planning process of investor-owned utilities in New Mexico. An amendment to this rule in 2022 (“updated IRP Rule”) resulted in several material changes to the planning process.

First, the updated IRP Rule specifies a new requirement for IRPs to include a **“statement of need,”** which defines the necessary resources, as determined by the utility. The statement of need is a general description of the resources that PNM anticipates needing to satisfy its planning goals; it builds upon the MCEP, which prescribes resource needs more objectively. The Statement of Need can serve as a bridge between the IRP and procurement via Requests for Proposals (RFPs) or other solicitations. It also clearly communicates to stakeholders the types of resources needed by PNM to achieve the planning objectives.

Figure 3. Three key outcomes of the 2023 IRP

Most Cost-Effective Portfolio	Statement of Need *N.M. Code R. § 17.7.3.10*	Action Plan *N.M. Code R. § 17.7.3.11*
Specific portfolio of resources that best meets PNM’s goals of reliability, affordability, and sustainability based on modeling results	Generalized description of the types and quantities of resources that PNM expects will be needed to satisfy planning objectives, based on MCEP and supporting analysis	List of specific actions PNM plans to undertake that will support execution of the MCEP and fulfillment of the Statement of Need

The second significant change to the updated IRP rule involves a new process for stakeholder engagement. Pursuant to this provision, the NMPRC appointed Gridworks to serve as an independent facilitator. With Gridwork’s assistance, broad access and organized dialog was shared with those who are invested in and impacted by PNM’s resource plans. Over the course of ten open stakeholder meetings, spanning nine months, dozens of participants provided questions and comments.

Figure 4. Highlights of the 2023 IRP facilitated stakeholder process

Developing the Most Cost-Effective Portfolio

PNM's planning process seeks to balance three primary objectives: maintaining affordability, ensuring reliability, and mitigating its impact upon the environment. Table 1 describes each of these objectives in further detail.

Table 1. Key objectives of the IRP process

Objective	Description
Reliability	PNM customers expect steady, reliable electric service. To meet this expectation, PNM plans its system to maintain a loss of load expectation of "one day in ten years," aligned with common industry standards; doing so requires PNM to plan the generation portfolio to meet customer demands all hours of the year, including under increasingly severe extreme weather conditions. As PNM's plan to retire significant portions of the existing fossil generation portfolio over the planning horizon, the company will need to add new resources that, together, can reliably supply customers across all weather conditions.
Affordability	PNM considers comprehensive, lifecycle costs when determining the affordability of resources in its portfolio. Avoiding unnecessary expenses and minimizing costs to consumers is a central concept of affordability; however, it is also important to maintain a more nuanced perspective to manage costs over the long term. Therefore, PNM's view of affordability also includes mitigating potential risks and volatility in the future. While all of the resource options leverage a competitive procurement process in an effort to minimize costs, PNM also considers many other factors in making resource selections. By focusing on the big picture and accounting for elements like compliance, climate change, fuel availability, or social impact, PNM can maximize value to customers.
Environmental Impact	PNM has established an ambitious goal to achieve a 100% carbon-free generation portfolio by 2040. As of 2022, the generation portfolio met 53% of customers' total annual energy needs (10,000 GWh) with carbon-free electricity. PNM's plan must therefore include sufficient new carbon-free resources to displace the remaining fossil generation in the current portfolio and meet future load growth – a total incremental need of 10,000 GWh of carbon-free energy by 2042.

The process used to create a portfolio that balances these objectives and serves as the MCEP was technically robust and collaborative:

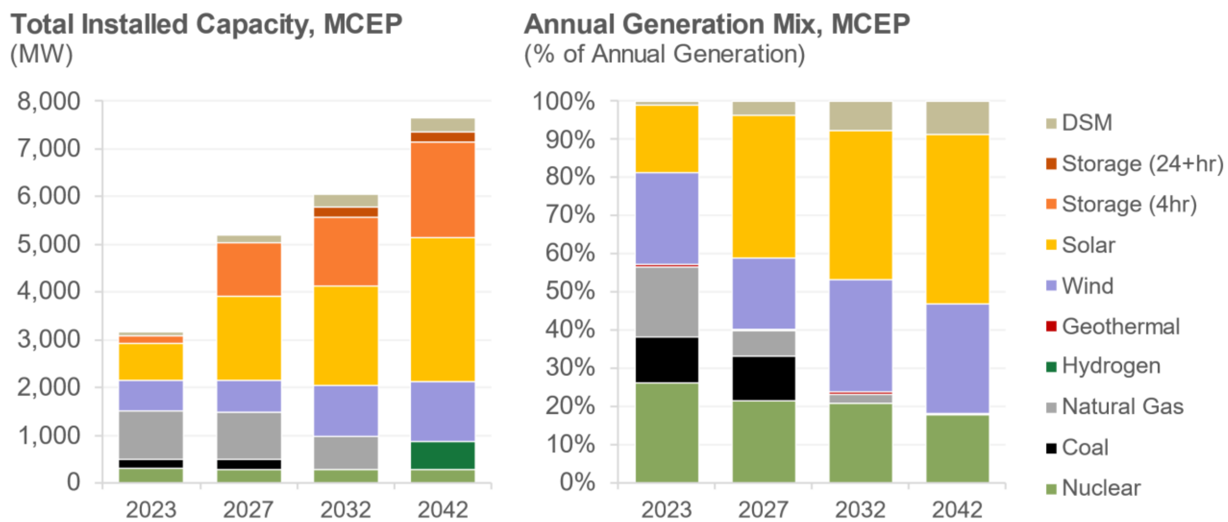
- PNM evaluated **hundreds of scenarios and sensitivities** over the course of the IRP process to explore impacts of different decisions and the implications of future risk factors and uncertainties upon plans. These scenarios were analyzed in multiple phases during the IRP process, which allowed PNM to refine plans through an iterative modeling process.
- PNM utilized **industry-leading portfolio analysis tools** to develop and evaluate optimized portfolios. These include EnCompass, a capacity expansion and production simulation model that optimizes and simulates portfolios least-cost resources to meet future needs; and Strategic Energy & Risk Valuation Model (SERVM), a loss-of-load probability model that provides detailed reliability analysis of portfolios. Both models are widely used and highly regarded throughout the industry for their sophistication and

suitability for analysis of portfolios with high penetrations or renewables and energy storage.

- PNM sought **feedback from stakeholders** regularly throughout the process. At various points throughout the facilitated stakeholder process, stakeholders had opportunities to ask questions, challenge assumptions, provide input, review draft modeling results, and provide recommended language to frame the statement of need and action plan.

The resulting **MCEP**, illustrated in Figure 5, represents the culmination of this extensive analytical and stakeholder process. The scale of the transformation of the portfolio over this twenty-year horizon is dramatic: to eliminate carbon-emitting resources from PNM's portfolio, the total amount of installed capacity of in the resource portfolio more than doubles over this period. The new generation additions over this period reflect a diverse mix of renewable and storage resources that include both mature and emerging technologies. These new investments allow PNM to rely less and less over time on today's existing carbon-emitting resources; some of these plants will exit the portfolio while others will remain throughout most of the planning horizon, rarely used but serving in a critical role as a backstop to reliability. In the MCEP, remaining existing resources that have traditionally relied upon fossil fuels transition to carbon-free fuels, consuming green hydrogen by 2040 and beyond in the final transition to a carbon-free system.

Figure 5. Installed capacity & annual generation mix of the Most Cost-Effective Portfolio at four key milestones: (1) present day; (2) at the end of PNM's Action Plan window; (3) after the planned 2031 exit from Four Corners; and (4) at the end of the planning horizon.



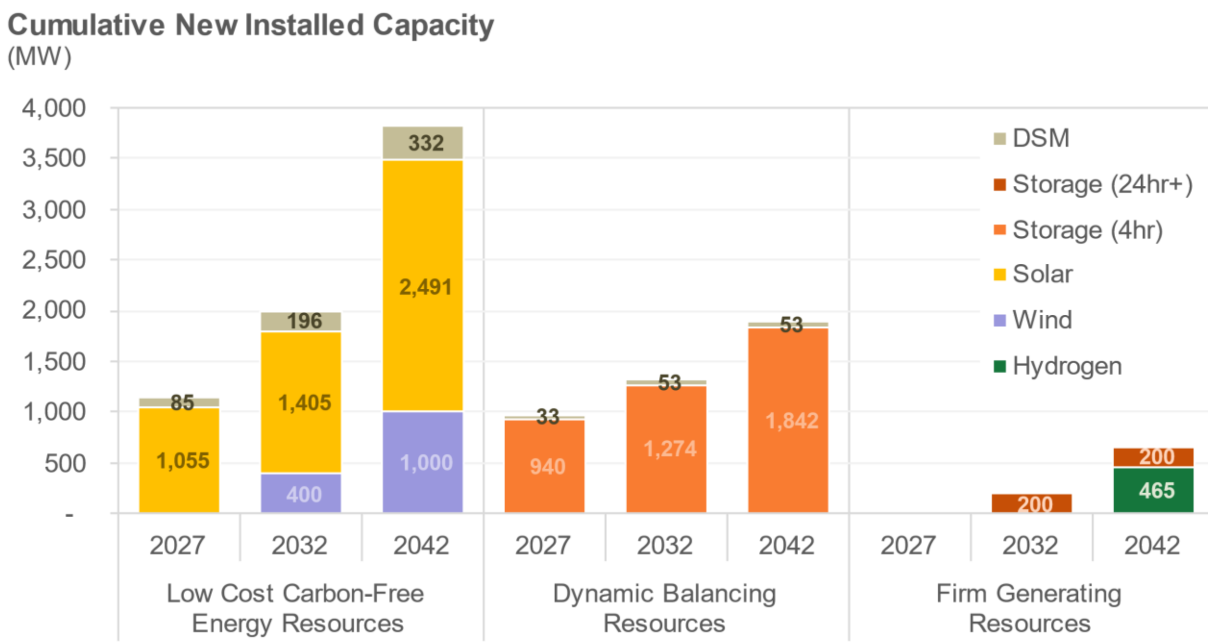
Statement of Need

Based on what PNM knows today and its expectations for the future, the Most Cost-Effective Portfolio reflects the current vision of the resources that would best fulfill future needs. Figure 6 summarizes the new resource needs in the MCEP at three key milestones: 2027, at the end of the Action Plan; 2032, following 2031 exit from FCPP and the end of the depreciable life of Reeves; and at the end of the planning horizon in 2042.

- Between now and 2027, PNM plans to meet most of its needs with 1,100 MW of low-cost carbon-free resources and 1,000 MW dynamic balancing resources, most of which are already under development (in some cases, pending approval by the NMPRC) or will be procured through active solicitations.
- Between 2027 and 2032, PNM's resource needs grow due to load growth and plant retirements, and during this period, the MCEP identifies an additional 900 MW of low-cost, carbon-free energy resources, 400 MW of dynamic balancing resources, and 200 MW of firm generation resources.
- Between 2032 and 2042, the MCEP identifies an additional 1,800 MW of low-cost carbon-free resources, 600 MW of dynamic balancing resources, and 500 MW of new firm generating resources in this last decade in the planning horizon.

Additional details on the MCEP can be found in the Appendices.

Figure 6. Summary of future resource needs in the Most Cost-Effective Portfolio



Cumulative figures reflect all new resource additions beginning in 2024, inclusive of projects under development:

Solar PV: *Atrisco (300 MW), Quail Ranch (100 MW), San Juan (200 MW), Sky Ranch (190 MW), TAG I (140 MW), Community Solar (125 MW)*

Storage: *Atrisco (300 MW), Quail Ranch (100 MW), Route 66 (50 MW), San Juan (100 MW), Sandia (60 MW), Sky Ranch I (50 MW), Sky Ranch II (100 MW), TAG I (50 MW), distribution-level storage (12 MW)*

DSM: *2024 & 2025 approved DSM programs*

While the MCEP reflects the current view of the most viable pathway to PNM's 2040 carbon-free goal, there are multiple uncertainties that may change the composition of the portfolio. By studying a diverse range of scenarios in this IRP, planners and stakeholders will have information to understand and assess the options and influencing factors that may lead PNM to change course from the current MCEP. In this regard, the IRP explores all viable pathways to decarbonization by 2040, while recognizing that the numerous future alternatives and sensitivities studied broaden the range of plausible resource needs going forward:

Table 2. Ranges of new capacity additions across the planning period

	Ranges of Cumulative New Installed Capacity (MW)		
	Through Action Plan Window (2027)	Through Medium Term (2032)	Through Planning Horizon (2042)
Low-cost carbon-free energy resources	1,100 – 1,200	1,500 – 2,200	3,300 – 4,500
Dynamic balancing resources	900 – 1,000	1,000 – 1,700	1,600 – 3,300
Firm generating resources	0	0 – 500	500 – 900
All resources	**2,000 – 2,100**	**3,100 – 3,700**	**5,800 – 8,000**

Ranges shown informed by results across four scenarios (All Technologies, Base Technologies + CT, Base Technologies + LDES, and Base Technologies + CT + LDES) across all sensitivities excluding Stable ED (high load growth). Resource needs under a high load growth future could be considerably higher.

The specific resources procured to meet those needs will include a diverse mix of technologies. Many of these resources are commercially available today, but the pursuit of aspirational goals often requires a transformative approach. Therefore, PNM will continue to explore innovative solutions like long-duration storage and hydrogen fuels as they approach commercial viability. PNM recognizes the importance of early action in the lifecycle of technology maturation, and to the extent practical opportunities arise, PNM will partner with others in the industry to engage in pilot programs and small-scale demonstrations of emerging technologies.

The development of new generation resources at the scale needed to meet the challenges ahead has implications for other parts of the system. In particular, the new resources added to decarbonize the generation mix and meet growing loads will require an expansion of the transmission system to allow for the delivery of electricity. The existing transmission system is already encountering constraints today, and many of the resources that may help to satisfy future needs are located in parts of the state that would require new transmission investments.

Ultimately, the specific portfolio of resources that best meets the needs of PNM's customers and achieves its goals will be determined by a combination of market forces, technological advances, and industry trends that cannot be perfectly predicted today; further, specific decisions around procurement of new resources will occur through competitive solicitations to ensure customers benefit from the lowest cost options. PNM's planning and procurement processes are adaptive and iterative by design, and neither the presence nor the absence of any specific type of resource in the 2023 IRP MCEP is a prescriptive determination of what will or will not be procured to meet customer needs. This MCEP, coupled with the diverse outcomes in alternative plausible portfolios, informs an Action Plan that is intended to further PNM's progress towards its goals while preserving optionality to adjust to changing market circumstances.

Creating a Plan for Action

As the final result of the 2023 IRP, the Action Plan translates learnings from the IRP process into concrete, actionable steps that will support progress towards long-term system reliability and decarbonization. It reflects the fact that procurement processes to meet the 2026-2028 resource needs are already underway and focuses on actions that will lay the foundation for the continued transition towards a carbon-free system. Many of the elements of the Action Plan have been heavily influenced by the feedback from stakeholders throughout the facilitated process; additional detail on how this feedback influenced the development is provided in the body of the report.

1. Issue an all-source RFP for resources coming online between 2029 and 2032

- Utilize an independent evaluator as part of the RFP process;
- Consider environmental justice factors in the bid evaluation process;
- Include system reliability and resiliency assessments, specific preferred transmission location(s) and constraints, fuel security, and resource diversity in the bid evaluation process;
- Leverage federal sources of funding, including the IRA, to the extent practical in alignment with system resource timing needs; and
- File well in advance for resource approvals with the NMPRC (PPA/CCN), balancing resource selections between utility-owned and third-party contracts to ensure project timelines properly support reliability.

2. Issue an RFI/RFP for long-lead time resources or newer technologies that could deliver between 2029 and 2035

- Consider environmental justice factors in the bid evaluation
- Continue to assess longer term needs of the system, including potential transmission expansions, to help facilitate long lead or newer technology additions;
- Continue to monitor the state of maturation of emerging technologies that are not yet commercially viable or cost-effective;
- Participate in coordinated studies and pilot programs for emerging technologies as practical and appropriate; and,
- Encourage solicitation of federal sources of funding, including the IRA, to the extent practical in alignment with system resource timing needs.

3. Evaluate opportunities to abandon FCPP earlier than 2031 as available and in the interest of customers

- Address the energy and capacity implications of removing this resource from the portfolio earlier than scheduled;
- To the extent that abandonment of FCPP and replacement resources are available and provide benefit to PNM customers, file for abandonment of FCPP interest; and,
- Seek IRA funding, including the “energy community” bonus, to maximize benefits, mitigate financial costs, and promote an equitable transition.

4. Evaluate the ability to create new (or improve existing) demand response and other customer programs (e.g. customer sited storage, interruptible rates)

- Continue to develop and implement cost effective energy efficiency and demand management programs and file plans with the Commission, as applicable;
- Continue to explore, develop, promote and refine, dynamic pricing structures (e.g., TOU) offered by PNM to empower customers and promote an efficient use of the system;
- Engage with stakeholders and seek feedback regarding potential new customer programs that could be enabled through Gridmod/AMI and consider how these could be incorporated in future IRPs; and
- Consider new DR programs, including flexible requirements, with the goal of improving performance during peak risk periods.

5. Assess the ability to add capacity at PNM's existing plant sites

- Conduct site assessments for resources approaching the end of contract or end of depreciable life to study (1) transmission impacts for potential alternatives pursuant to the FERC Open Access Transmission Tariff rules and (2) the necessity of extending operations of existing resources to enable reliable operations of the system;
- Continue to explore options to expand the capability of existing plant resources when evaluating alternatives to meeting future customer needs, also pursuant to the FERC Open Access Transmission Tariff rules; and
- Examine potential non-wires solutions where feasible to increase existing plant capacity or operational flexibility.

6. Continue to explore the expanded participation in regional markets

- Explore PNM's ability to make a binding commitment to Western Resource Adequacy Program (WRAP) sooner than 2028;
- Actively explore joint regional market opportunities, formal or informal, to assess the potential customer benefits associated with market participation. Provide input, when possible, to explore benefits associated with extreme event(s) both from a cost and performance perspective.

7. Assess the need to utilize other reliability metrics in planning

- Transition resource adequacy modeling approach to reflect WRAP planning requirements and resource attributes no later than PNM's 2026 IRP;
- To the extent these resource attributes and planning requirements are known, and PNM makes a binding commitment to fully participate in WRAP earlier then 2028, update resource adequacy modeling for PPA and/or CCN filings, targeting prior to filing the 2026 IRP if possible;
- Continue to monitor whether the loss of load expectation (LOLE) standard of 0.1 days per year is sufficient for planning;
- Assess whether additional metrics should be utilized in resource adequacy planning and/or whether standards for resilience should be established for planning; and

- Explore additional methods to evaluate incorporation of distribution planning concepts into Integrated System Planning.

8. Initiate stakeholder workshops and meetings for the 2026 IRP in advance of the required six-months stakeholder process as required under the IRP Rule

- Investigate improvements to IRP process to incorporate integrated transmission, and distribution into more integrated system planning;
- Request input from stakeholders at the outset of the 2026 IRP stakeholder process regarding areas of focus and prioritization of activities for the 2026 IRP, including consideration of recommendations emanating from the 2023 IRP process; and
- Investigate ways to provide meaningful education and outreach for stakeholders and enhance engagement for the 2026 IRP cycle.

9. Complete the 2026 IRP

- Address the implications of the expiration of supply contracts and any retiring resources;
- Investigate potential optimization of generation, storage, and transmission to enhance planning efforts; and,
- Work with stakeholders in an ongoing collaborative public advisory process, including communication of electricity sector changes and the IRP process.

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1 Introduction

Public Service Company of New Mexico's (PNM) 2023 IRP lays out an aggressive plan to achieve a carbon-free portfolio by 2040. PNM's last IRP was published in early 2021, shortly after PNM established a goal to transition to a carbon-free energy system by 2040. The 2020 IRP laid out an ambitious vision to achieve that transition while maintaining reliability with a portfolio of renewables, energy storage, and firm resources.

Three years later, as in the sixth Integrated Resource Plan, PNM remains firmly committed to the long-term goal to transition to a carbon-free system. In this time, PNM has built confidence in this vision, gaining experience operating the system with new technologies and successfully retiring the largest, most carbon-intensive power plant in the portfolio. The landmark Inflation Reduction Act was also passed in this period, and the anticipation of its economic stimulus has created optimism that federal tax benefits could unlock more affordable pathways to a clean energy future.

Each IRP provides an opportunity to refine PNM's plans to meet the challenges ahead as the future comes into sharper focus. Over the next eight years, the portfolio will continue to undergo significant transformation. Between the expiration of the power purchase agreement with Valencia, a 2031 exit from the Four Corners Power Plant (FCPP), and end of the depreciable life of Reeves Generating Station, the portfolio stands to lose over 500 MW of firm generating capability, representing roughly one quarter of present peak demand. These changes reshape the resource portfolio and move the system toward carbon-free, as replacing this capacity while meeting load growth will require significant quantities of new resources.

Key Term ***Firm generating resources*** *are generating resources capable of operating at or near full capacity for extended periods of time when needed to maintain system reliability under the most constrained conditions, including periods of high demand or low output from other supply resources.*

While there is great opportunity ahead, there is also great challenge. PNM must proceed forward with a sense of urgency. Many of the options require years of lead time and preparation to integrate into the portfolio. Permitting and development timelines require years to complete – and more recently, have extended beyond historical norms – which means planning must be done today for 2030 system needs. Achieving a reliable, sustainable, and affordable portfolio requires proactive planning and deliberate, sustained action.

PNM's commitment to decarbonize its generation portfolio aligns with the state of New Mexico's policy to achieve deep reductions to its carbon footprint. In addition to supporting the passage of the landmark Energy Transition Act (ETA), New Mexico's Governor issued Executive Order 2019-003, joining the US Climate Alliance in support of the 2015 Paris Agreement and establishing a goal to reduce economy-wide emissions by 45% by 2030 (relative to 2005 levels). As the largest public utility in New Mexico, PNM recognizes its role in meeting this goal and others. As such, this IRP takes on a scope beyond the traditional IRP by demonstrating plans to mitigate a significant portion of the PNM's emissions.

The purpose of the IRP is to identify the types of resources that PNM will need in the future to continue to provide reliable electric service at the lowest possible costs while meeting or exceeding regulatory and environmental objectives. PNM prepared the plan in accordance with applicable rules and regulations, as well as industry standard planning principles. The IRP including the Statement of Need and Action Plan are based on a rigorous analysis of an array of commercially available resource options that consider a variety of future conditions.

1.1 IRP Planning Framework

Updated IRP Rule

PNM has prepared this IRP in accordance with 17.7.3 New Mexico Administrative Code (NMAC), Integrated Resource Plans for Electric Utilities (IRP Rule). The IRP Rule was originally issued by the NMPRC on March 1, 2007, and has been amended on four occasions, most recently on October 27, 2022. As established by the IRP Rule, the purpose of the IRP is to identify the most cost-effective portfolio of resources to meet the future needs of customers:

> The objective of this rule is to set forth the commission's requirements for the preparation, filing, review, and acceptance of integrated resource plans by public utilities supplying electric service in New Mexico in order to identify the most cost-effective portfolio of resources to supply the energy needs of customers.

– 17.7.3.6A NMAC

The IRP Rule further requires that New Mexico electric public utilities file an IRP every three years that includes the following information (17.7.3.89B 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 determination of resource portfolios;
- A Statement of Need;
- An Action Plan

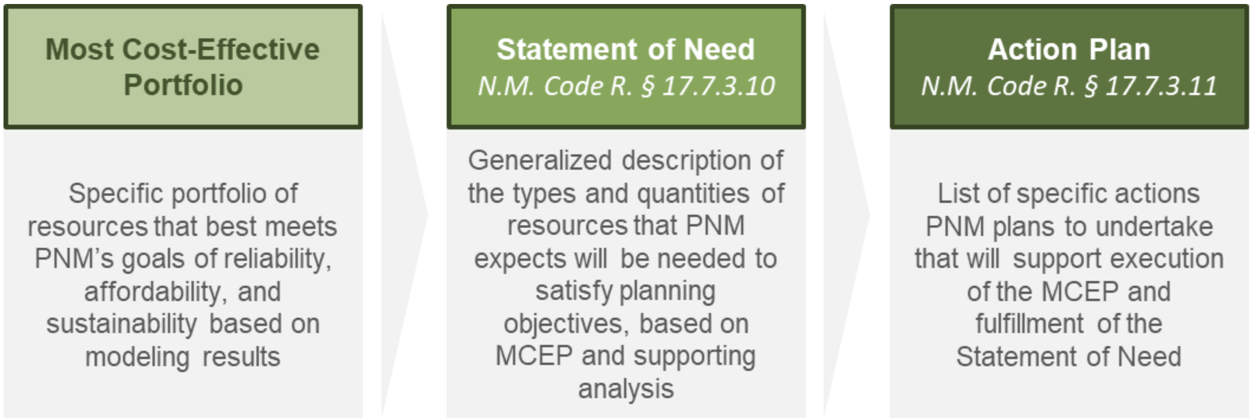
The requirement to establish a Statement of Need has not been a required element of previous iterations of the IRP Rule. The Statement of Need requires this IRP to clearly articulate what types and quantities of resources will be needed to meet future resource needs:

> A. The statement of need is a description and explanation of the amount and the types of new resources, including the technical characteristics of any proposed new resources, to be procured, expressed in terms of energy or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies.
>
> B. The statement of need shall not solely be based on projections of peak load. The need may be attributed to, but not limited by, incremental load growth, renewable energy customer programs, or replacement of existing resources, and may be defined in terms of meeting net capacity, providing reliability reserves, securing flexible resources, securing demand-side resources, securing renewable energy, expanding or modifying transmission or distribution grids, or securing energy storage as required to comply with resource requirements established by statute or commission decisions.

– 17.7.3.10 NMAC

The updated IRP Rule also required this IRP to designate a "Most Cost-Effective Portfolio" (MCEP) as part of its stated objective. The determination of the MCEP serves as an important step in creating the Statement of Need and Action Plan. Figure 7 illustrates the relationship Most Cost-Effective Portfolio, the Statement of Need, and the Action Plan.

Figure 7. Relationship between the Most Cost-Effective Portfolio, Statement of Need, and Action Plan



The updated IRP Rule also is the established of a "facilitated stakeholder process. In previous IRP cycles, as well as in this IRP cycle prior to the amendment of the IRP rule, PNM has led its own stakeholder engagement processes in an effort to promote transparency and collaboration. The facilitated stakeholder process established by the new rule continues PNM's previous efforts under the oversight of an independent third party selected by the Commission." Which expands the transparency of this planning process and allows third-party stakeholders to have direct input into this IRP. Through this process, PNM's Statement of Need and Action Plan have been created with consultation and input from stakeholders and the New Mexico Public Regulation Commission (Commission). PNM provided IRP stakeholders are further empowered by the ability to access, under confidentiality, the IRP modeling software used in this IRP, enabling and perform their own independent analysis.

The facilitated stakeholder process continues after PNM files its IRP. The existing process by which stakeholders comment on the filing will become more interactive, as PNM replies to all stakeholders having either adopted their proposed changes or providing a rationale for not doing so. The updated IRP rule amendments provide increased opportunity for stakeholders' engagement to shape in PNM's planning process from start to finish.

IRP Planning Process

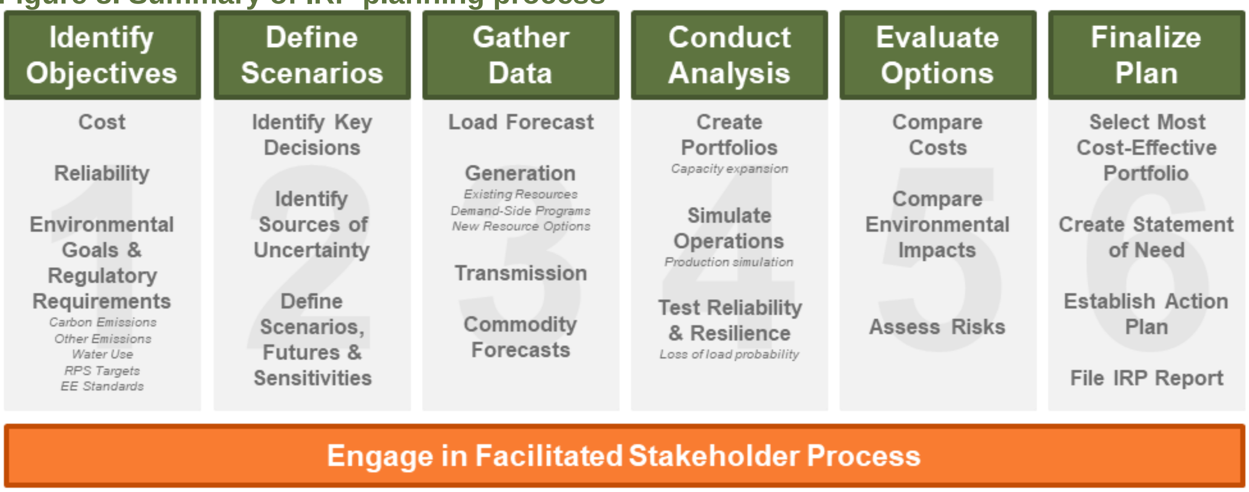
The IRP planning process identifies the mix of resources that, together, reliably meets system operational requirements, adheres to regulatory requirements, and mitigates environmental impacts, all while minimizing costs to customers. This planning process ensures PNM can respond to projected future events and ensure adequate resources are available to meet a variety of expected system conditions demand and maintain service reliability. The IRP is renewed every three years, with earlier notifications to the NMPRC and stakeholders if material changes in assumptions would lead to a revised course of action.

The 2023 IRP planning process horizon spans a 20-year time period; for this IRP, the horizon considered spans between 2023 through 2042. The last three years of the 2023 IRP is unique for PNM as it reflects PNM's pledge to meet all customers' energy needs with carbon emissions-free resources. By evaluating PNM's IRP portfolios that incorporate milestone requirements set forth in the ETA through the complete transition to its goal, PNM strives to demonstrate that the actions undertaken herein are not only in the best interests of customers today but will enable its complete transition to a carbon-free portfolio by 2040.

The IRP process is forward-looking, and therefore subject to uncertainty; wherever possible, PNM mitigates this uncertainty by relying on 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.

PNM engaged in a robust and collaborative process for its IRP analyses to identify the MCEP, develop the Statement of Need, and establish the Action Plan. 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—all summarized in Figure 8. Throughout the process, the PNM Integrated Resource Planning team worked to solicited and incorporated input from participants in the IRP public advisory group and facilitated stakeholder processes. Key areas where stakeholders contributed valuable perspectives included in the scenario design of scenarios, which technologies and combinations of technologies to include in various scenarios, and evaluation of the potential of different demand-side resources. Details regarding the IRP public advisory group and the facilitator stakeholder process is described in the Section 1.2.

Figure 8. Summary of IRP planning process



Relationship to Transmission Planning Processes

PNM is one of over 60 transmission service providers in the Western Interconnection. As a transmission operator and transmission owner, it provides open access transmission service under a standard FERC tariff to serve the needs of both retail customers and wholesale customers. PNM operates the transmission system within a NERC-certified Balancing Authority Area (BAA), the PNM BAA. PNM monitors key transmission paths within the BAA and interconnections to other BAAs 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 its role as a transmission service provider, PNM serves both retail loads and network customers pursuant to its Open Access Transmission Tariff (OATT) as approved by the Federal Energy Regulatory Commission (FERC). Currently, wholesale customers account for 50% of the utilization of PNM's transmissions system. These system customers fall into two categories: Network Integration Transmission customers and Point-to-point customers.

PNM plans the transmission system to meet the needs of all customers, including retail and wholesale customers pursuant to PNM's Open Access Transmission Tariff ("OATT"). To ensure those needs can be met, PNM develops a ten-year plan each year to assess long-range transmission needs in accordance with the North American Electric Reliability Corporation (NERC) TPL-001 mandatory Reliability Standards. Attachment K of PNM's OATT additionally outlines PNM's local transmission planning process to identify range of transmission-related needs:

- Provide adequate transmission to access sufficient resources in order to reliably and economically serve retail and network loads.
- Where feasible, identify NWA's (non-wires alternatives) such as demand response that could meet or mitigate the need for transmission additions or upgrades.
- Support PNM's local transmission and sub-transmission systems.
- Provide for interconnection for new generation resources.
- Coordinate new interconnections with other transmission systems.
- Accommodate requests for long-term transmission access.
- Consider transmission needs driven by Public Policy Requirements.

The scope of the transmission planning studies that occur as part of this process differ from the IRP planning process in several key respects:

1. PNM's transmission planning accounts for both retail and network customers, whereas the updated IRP Rule 17.7.3.7.I(1) NMAC, by definition, is limited to, "meet New Mexico jurisdictional retail customers' existing and future demand" focuses exclusively on planning a resource portfolio for PNM's retail customers;
2. PNM's transmission planning studies require use of a different set of models including positive sequence load flows and electromagnetic transient models that provide a granular view of the transmission system versus the capacity expansion modeling than the tools currently used to develop resource plans; and
3. PNM's transmission planning studies occur once each year and span a ten-year planning horizon, while the IRP process is conducted over a three-year cycle and spans a twenty-year planning horizon.

These differences notwithstanding, PNM recognizes that its future portfolio requires continual improvement in coordination to develop new generation resources at a large scale and the complementary transmission needed to deliver those resources to loads. While the task of identifying specific transmission lines and elements necessary to meet future retail and wholesale needs is beyond outside the scope of the updated IRP Rule, PNM's IRP accounts for the expected costs to upgrade the transmission system as new generation is added to the system based on information provided by the PNM Transmission Planning team.

PNM also recognizes a growing level of interest in "Integrated System Planning" in the industry, and as such, PNM recently combined the formerly separated IRP and Transmission Planning teams to evolve its processes within a utility within a single coordinate planning process to meet the growing need to expand transmission to support the energy transition. This will allow for additional transmission analysis to be further incorporated in future IRPs, PNM continues to seek out opportunities to continue to improve the integration of its planning activities.

Key Term ***Integrated System Planning (ISP)*** *refers to a coordinated process in which a utility develops a single long-term plan that links together the different elements of its system – which may include generation, transmission, distribution, and customer programs.*

1.2 Public Stakeholder Process

Active and broad stakeholder participation is a crucial element to a successful planning process that serves the public interest of the state of New Mexico, and the diversity of perspectives that PNM's stakeholders offer enhances the quality of the IRP. The most recent revisions in the updated IRP Rule also place a greater emphasis on transparency and the importance of robust stakeholder participation. As described in the updated IRP Rule:

> At least six months prior to the filing of its IRP, the utility shall notify the commission, members of the public, the New Mexico attorney general, and all parties to its most recent base rate case and most recent IRP case of its intent to file an IRP. The commission, upon notification, shall initiate a facilitated process for the utility, commission utility division staff, and stakeholders to reach a potential agreement on a proposed statement of need pursuant to 17.7.3.10 NMAC and an action plan pursuant to 17.7.3.11 NMAC.
>
> – 17.7.3.9 NMAC

The updated IRP Rule further specifies that the utility must engage in a facilitated stakeholder process led by a NMPRC appointee.

PNM's stakeholder engagement efforts for this IRP occurred in two phases. Prior to the updated IRP Rule establishing the facilitated stakeholder process, PNM initiated a series of public meetings as a forum to share and solicit feedback from the general public on a range of topics relating to the IRP. Between April 2022 and March 2023, PNM hosted 11 open workshops covering IRP analysis and process. PNM's second phase began in March 2023, following the NMPRC's appointment of GridWorks to lead the facilitated stakeholder process. A full schedule of stakeholder workshops through both processes is provided in Table 3 and Table 4 and a detailed summary of meetings and discussions across all stakeholder workshops can be found in Appendix O.

Table 3. Public Advisory Group meetings (hosted prior to facilitated stakeholder process)

Meeting Date	Key Topics
April 28, 2022	• PNM 2023-2042 Integrated Resource Plan Kickoff
May 25, 2022	• Reliability & Resiliency
June 8, 2022	• Resource Adequacy Modeling
June 22, 2022	• Energy Efficiency • Resilience Analysis & Market Depth
July 6, 2022	• Load Forecast • Candidate Resource Pricing Methodology
July 27, 2022	• IRP Modeling Updates / Techniques
August 17, 2022	• Public Advisory Group Day
Sept 13, 2022	• Transmission (1 of 2)
Oct 6, 2022	• Transmission (2 of 2)
Oct 17, 2022	• Emerging Technologies & Evolving Grid Solutions

Meeting Date	Key Topics
Nov 2, 2022	• Commodity, Pricing Forecasts & Scenario Process
Dec 15, 2022	• Load & DGPV forecast • Pricing TOD • Siemens market price forecast
Jan 17, 2023	• Energy efficiency bundles program & highlights • PRM & ELCC • Summer 2022 imports • Scenario form
Feb 15, 2023	• IRP rule • Overview of existing system • Economic development scenarios for IRP • Modeling framework & round 1 scenarios
Mar 15, 2023	• Updated IRP Rule • Gridworks Introduction and Modeling Run Requests

Table 4. Public Advisory Group meetings (facilitated stakeholder process)

Meeting Date	Key Topics
March 28, 2023	• Stakeholder Engagement Kick-Off
May 4, 2023	• Building a Shared Foundation of Knowledge & Collecting Statement of Need Ideas
May 18, 2023	• Statement of Need outline • Proposed modeling engagement plan & formation of modeling core team
June 1, 2023	• Statement of Need update • Modeling Update
June 15, 2023	• Statement of Need update • Modeling update
June 29, 2023	• Stakeholder modeling observations • Modeling update • Action Plan workshop
July 27, 2023	• Update on 2026 RFP results • Modeling Update • Statement of Need update
August 31, 2023	• Modeling Update: Phase 1, 2, and stakeholder scenario update • Statement of Need update • Action Plan discussion
September 28, 2023	• Modeling Update: Phase 3 and stakeholder scenario update • Statement of Need update • Action Plan discussion
October 6, 2023	• Modeling Update: Phase 3 resilience update • Statement of Need update • Action Plan discussion
October 19, 2023	• Modeling Update: Stakeholder scenario update • Statement of Need discussion • Action Plan discussion
December 19, 2023	• Reflections on the process

Over the course of this eighteen-month process, stakeholders contributed to the development of the IRP in many meaningful ways. Notably, stakeholders:

- Contributed a range of recommendations for scenarios to study, several of which feature prominently in the final analysis;
- Brainstormed topics and presented language for inclusion in the Statement of Need PNM for discussion;
- Offered suggestions for PNM's Action Plan; and,
- Provided perspectives that challenged conventional thinking and, ultimately, led to a more robust product.

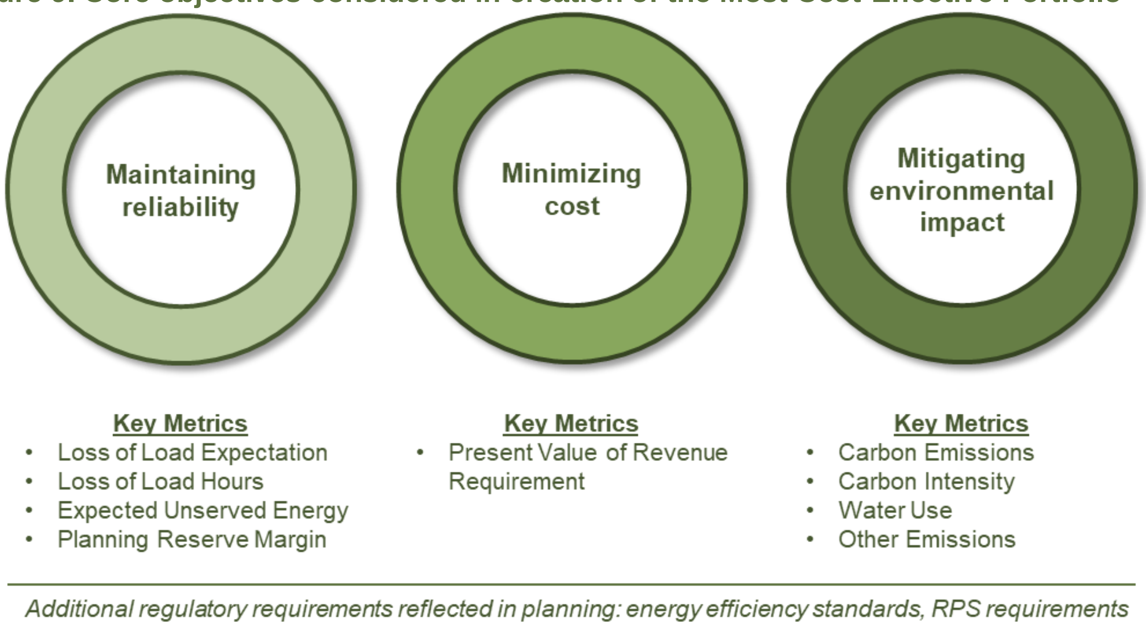
Throughout this document, PNM highlights the most prominent and direct stakeholder contributions that helped to shape the ultimate plan.

PNM values the many hours that stakeholders dedicated to this effort. Included in Appendix O is a summary of the meetings and an inventory of questions and answers discussed in those meetings. Going forward, continued stakeholder engagement will help shape the future of PNM's resource portfolio and invite any interested parties that wish to contribute to the process to notify PNM of their interest.

1.3 Planning Objectives

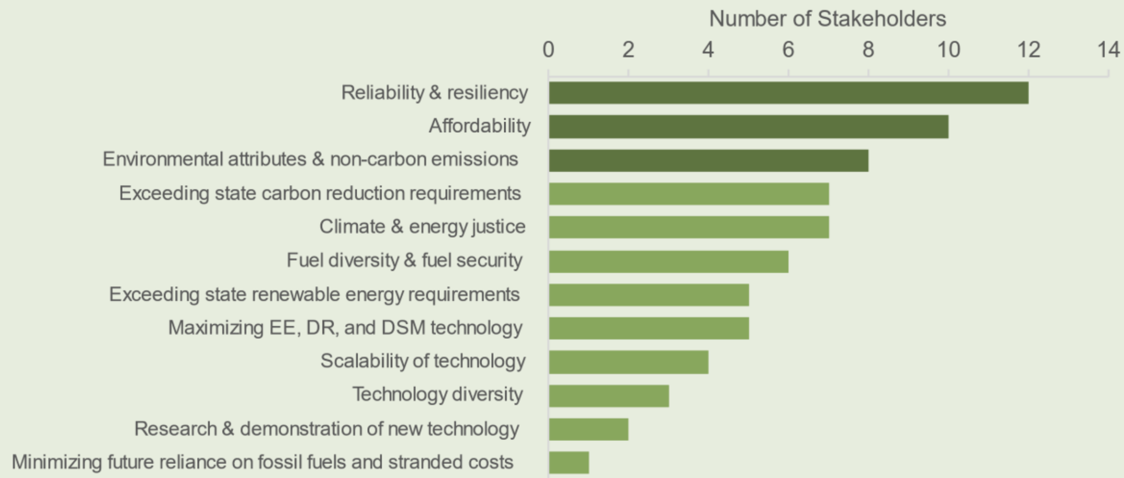
Consistent with the objectives used in the past to develop the IRPs, this IRP aims to identify a portfolio of resources that meet customer electricity supply needs reliably, with limited environmental impact, and at the lowest reasonable cost. Additionally, as was the case in the 2020 IRP, PNM sought to create an MCEP that demonstrates a plausible transition plan to achieving 100% carbon-free generation by 2040. A secondary objective of this IRP is to study and outline the challenges and uncertainties PNM expects in pursuit these ambitious goals, demonstrating how the Action Plan mitigates those challenges.

Figure 9. Core objectives considered in creation of the Most Cost-Effective Portfolio



Stakeholder Input: Prioritizing Objectives for PNM's 2023 IRP

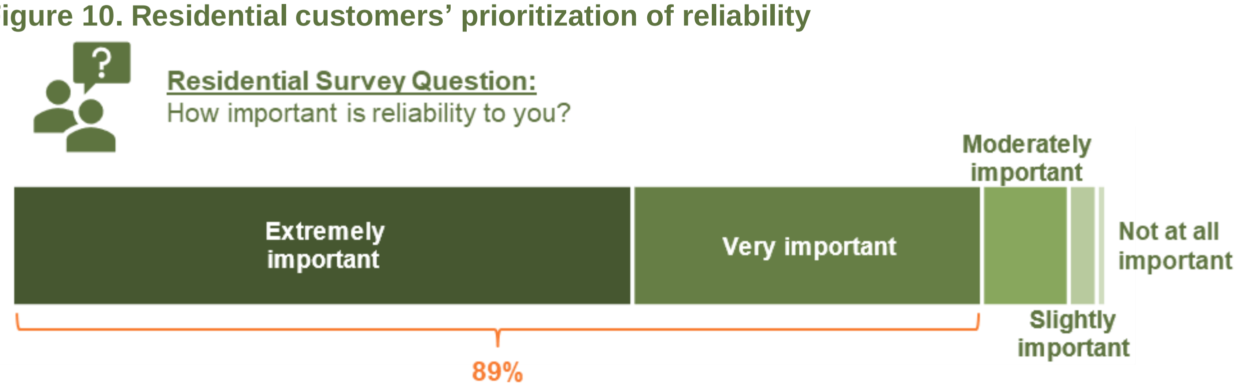
After helping to brainstorm possible priorities for PNM's planning process, stakeholders were asked to identify their top five priorities. Fourteen stakeholders responded to this survey. While stakeholders did collectively identify a wide range of priorities, the three items with the highest level of support among stakeholders aligned with PNM's three planning objectives of reliability (12 of 14 respondents), affordability (10 of 14), and environmental impact (8 of 14).



Reliability

Reliable electric service for PNM's customers is of paramount importance. They expect and rely on stable, reliable electric service for their homes and businesses, and fulfilling this obligation is a matter of public welfare and safety. In a recent survey, 89% of residential customers responded that it was either "extremely important" or "very important" to minimize electricity disruptions or outages.

Figure 10. Residential customers' prioritization of reliability



PNM prioritizes reliability as a required condition for all portfolios in the IRP planning process; this objective is consistent with the standards for electric service set forth in 17.9.560.13C NMAC:

> The generating capacity of the utility's plant supplemented by the electric power regularly available from other sources must be sufficiently large so as to meet all normal demands for service and provide a reasonable reserve for emergencies.

– 17.9.560.13C NMAC[1]

Ensuring reliability affects planning and selection of preferred electric portfolio(s) in multiple ways.

1. **Resource adequacy:** To ensure that there are enough resources owned by or under contract to PNM, the planning reserve margin aligns with an industry-standard target for **loss of load expectation (LOLE) of 0.1 days per year** ("one day in ten years"). In addition, PNM considers alternative reliability metrics, including **expected unserved energy (EUE)** and **loss of load hours (LOLH)** in plan development. In aggregate, this suite of metrics helps define the frequency, duration, and magnitude of potential reliability risks in the portfolio.

2. **Operational reliability:** PNM simulates the operations of the portfolios on an hour-to-hour basis throughout the year, reflecting the practice that PNM system operators follow in real time to balance loads and resources while maintaining **operating reserves** to comply with NERC reliability standards.

3. **Supply resilience:** Beginning in this IRP, PNM undertakes specific **"stress tests" under extreme weather conditions** to study the resilience of the generation mix and highlight systemic risks.

The first of these requirements establishes the quantity of resources needed in the portfolio to ensure an acceptable level of reliability; the second impacts how the resources in that portfolio must be operated on a day-to-day basis. These two requirements are linked: by ensuring that the portfolio meets the minimum planning reserve margin in each year, PNM can maintain operating reserves to comply with NERC requirements without shedding load in all but the most extreme conditions.

In this IRP, PNM continues to refine reliability planning practices under the Loss of Load Probability (LOLP) modeling framework to prepare the system for increased penetration of renewables and storage. In addition, "stress tests" examine the resilience of the portfolio under potential extreme weather conditions. The selected MCEP meets both the resource adequacy and operational reliability requirements and presents most resilience under extreme conditions.

Affordability

The IRP compares potential plans using the **net present value of revenue requirements across a 20-year period (2023-2042)** to identify the plan that meets reliability, environmental, and regulatory requirements at the lowest reasonable cost.

Each portfolio considered is constructed in a long-term capacity expansion model that minimizes the net present value of costs over the planning horizon subject to reliability, environmental and other regulatory requirements. The planning horizon costs, referred to as revenue requirements in the expansion planning modeling, includes capital costs, fixed costs, emission costs, fuel costs, variable costs, contract costs, net market purchase costs, and others.

A portfolio that optimizes cost while considering reliability and environmental impact within this complex and rapidly changing technological landscape must be flexible. The resource pathway

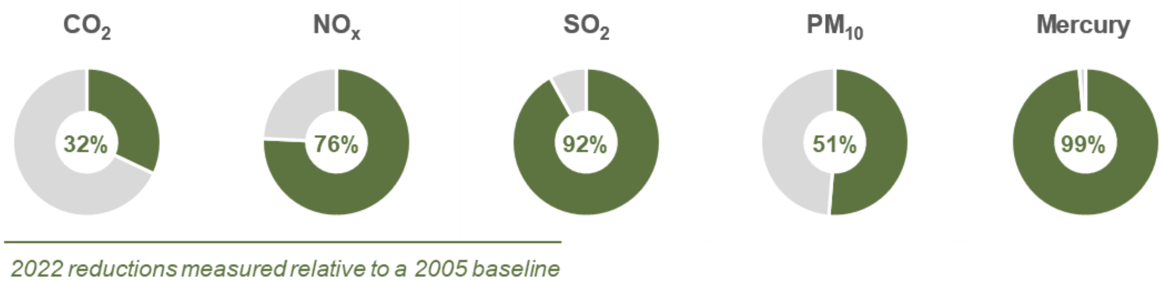
[1] http://164.64.110.134/parts/title17/17.009.0560.pdf

that appears least cost now is not guaranteed to remain the lowest cost path as costs and risks evolve. As a result, PNM cautions against determining a single 20-year resource plan based solely on the present-day evaluation of cost and risk. Maintaining a certain amount of flexibility in resource selection allows for re-optimizations at key decision points in the future when more information is available on the technologies that are only beginning to see widespread adoption now. This flexibility ensures that customer affordability takes advantage of the changing technology landscape instead of being threatened by it.

Environmental Impact

The third planning objective is to mitigate impact on the environment. Climate change is a vital issue that demands bold action, and PNM believes in the importance of mitigating impacts on the local environment. PNM hears the voices of stakeholders, from investors and customers, employees and community partners who are conscientious about reducing their own impact on the environment and are concerned about the greenhouse gas emissions associated with generating electricity with fossil-based resources. PNM agrees and is taking action to protect the environment and conserve natural resources while building a clean, secure and sustainable energy future. In the past two decades, PNM has taken action to reduce its impact on the environment; Figure 11 shows the reductions in greenhouse gas emissions and various criteria pollutants achieved since 2005.

Figure 11. PNM's reduction in emissions since 2005



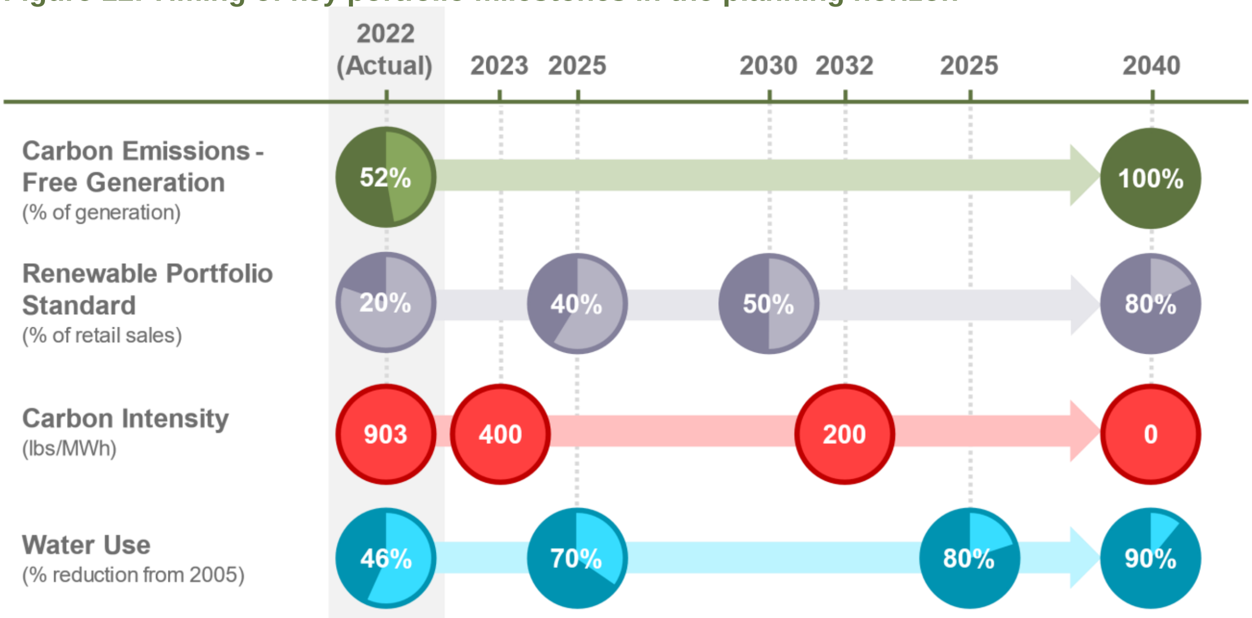
Going forward, PNM has established ambitious targets for its portfolio: transition to a carbon-free generation portfolio by 2040. PNM has also established a goal to reduce freshwater use by 90% by 2040.

PNM's goals complement the state's existing clean energy policies, including New Mexico's ETA, its Renewables Portfolio Standard (RPS) targets, and standards for energy efficiency established by the Efficient Use of Energy Act (EUEA). These regulatory requirements, established by the NMPRC and state legislature, will enable further improvements in efforts to limit environmental impact in the near- and long-term:

- Interim milestones for portfolio carbon intensity of 400 lbs/MWh by 2023 and 200 lbs/MWh by 2032 as required by the ETA;
- Minimum requirements for the RPS of 20% of retail energy sales no later than January 1, 2020, 40% in 2025, 50% in 2030, and 80% in 2040, all established by the ETA; and
- Energy efficiency spending of 3-5% of revenue requirements and annual savings goals of 5% of 2020 retail sales for the period 2021-2025.

Figure 12 summarizes environmental-related milestones as well as the goals – voluntary and otherwise – that PNM is pursuing over the next twenty years.

Figure 12. Timing of key portfolio milestones in the planning horizon



In the transition to a carbon-free portfolio, additional environmental factors may merit consideration in future planning as well – for instance, land use impacts of renewable development, mining for rare earth metals, and lithium disposal requirements for storage resources.

1.4 Review of 2020 IRP

Conducted after the passage of the ETA, the 2020 IRP introduced PNM's pathway and intended resource mix to meet the 2040 carbon-free goal. This section provides an overview of the 2020 IRP and progress made on its associated Action Plan.

Key Findings

The 2020 IRP focused on designing portfolios to meet PNM's 2040 carbon-free goal and comply with the requirements of the ETA. Across a range of sensitivities, PNM identified two cost-effective portfolios, "Technology Neutral" and "No New Combustion". The Technology Neutral portfolio was designed to achieve a reliable, carbon-free portfolio with a mix of solar, wind, storage, demand-side management (DSM), existing nuclear resources, and combustion turbines (CTs) repurposed to burn hydrogen instead of natural gas. The No New Combustion portfolio was designed to produce similar levels of reliability, but with additional solar and storage to replace the hydrogen CTs in the Technology Neutral portfolio. Despite differences in the two resource portfolios, both pointed to a common roadmap for future plans:

- **Replace coal and other baseload resources with renewables and storage**: The 2020 IRP determined that PNM could reduce costs for customers if PNM exited from leases in Palo Verde Nuclear Generating Station (PVNGS) in 2023 and 2024, as well as its share of FCPP in 2024. To that end, PNM issued RFPs to replace these generators and the San Juan Generating Station (SJGS) with renewable resources and storage as discussed in more detail in the next section.

- **Continue procuring renewables, storage, and demand-side resources to advance a carbon-free portfolio:** The most cost-effective portfolios in the 2020 IRP were primarily composed of solar, wind, and storage resources. PNM plans to procure increasing amounts of these resources to achieve the carbon-free goal in 2040. Along the way, PNM will file Annual Renewable Energy Procurement Plans to demonstrate compliance with New Mexico's Renewable Portfolio Standard (RPS).

- **Explore cost-effective options to maintain reliability:** A suite of approaches to maintain reliability to evaluate the shift away from fossil-fueled generators and toward a high-renewables system. These approaches included utilizing storage as a capacity resource to displace combustion-based generators, investments in emerging technologies like hydrogen-ready combustion turbines and exploring new rate designs that influence customers' peak loads. Additionally, PNM is adopting the industry standard of 0.1 loss of load expectation (LOLE) per year as a best practice for future resource adequacy planning.

- **Implement grid modernization and electrification programs:** The state of the electric grid is changing rapidly. Customers are increasingly interested in renewable energy, self-generation, and electrification as ways to reduce their bills and benefit the environment. Thus, PNM expects to see load profiles continue to evolve as electric loads and behind-the-meter supply resources are introduced to the system. New technologies will enable the system to adapt to these changes and remain in balance while empowering customers to continue taking control over their energy use. The 2020 IRP identified the "Wired for the Future" initiative, grid modernization plan, and transportation electrification program as important tools to achieve a reliable, climate-friendly system. PNM continues planning for increased electric loads from new and existing customers and monitor emerging technologies to maintain reliability.

Key Term ***Electrification*** *is the process of converting equipment powered by direct combustion of fossil fuels to electric alternatives. Common examples include electric vehicles, air-source heat pumps, electric water heaters, and induction stoves.*

- **Evaluate transmission needs:** The ability to deliver generation to load centers in northern and southern New Mexico is a key part of the planning process. PNM's transmission system will need to be updated as it continues to develop and procure high-quality wind and solar resources, many located in different regions than the current generators. The 2020 IRP identified potential projects to expand PNM's transmission and interconnect new renewable resources. Additionally, removing SJGS and FCPP from the resource portfolio will require mitigation of voltage control challenges in the Four Corners region.

Four-Year Action Plan

The 2020 IRP concluded with an Action Plan that identified strategic activities that would help PNM continue to reliably meet customers' needs and expectations at a reasonable cost. PNM has made significant progress towards the achievement of the 2020 Action Plan. Those action items not fully resolved between the 2020 and 2023 IRPs are revisited and explored within this plan. Table 5 provides a report of the status of key action plan items from the 2020 IRP.

Table 5. Status of key actions from 2020 Action Plan

Action Plan Item	Status
Continue to develop and implement energy efficiency and demand management programs	**Ongoing**
Add renewable energy resources to maintain compliance with the Renewable Portfolio Standard (RPS)	**Ongoing**
Explore options to maintain system supply and reliability • Join the California Energy Imbalance Market • Transition to 0.1 LOLE for PNM's reliability standard • Consider firm, non-combustion resources to replace PNM's fossil fueled generators	**Complete**
Procure replacement resources for SJGS	**Complete**
File for PVNGS lease abandonment and identify replacement Capacity	**Complete**
File for FCPP abandonment and issue an RFP for replacement	**Complete**[A]
Implement Community Solar, PNM's Transportation Electrification Plan, Wired for the Future Initiative, and new rate designs	**In Progress**
Conduct the 2023-2042 Integrated Resource Plan	**Complete**

Table Notes

A. PNM filed an application to abandon its share of FCPP in 2021 in Case No. 21-00017-UT. This application was rejected by the NMPRC, and PNM's appeal at the New Mexico Supreme Court was subsequently denied.

1.5 Updates Since 2020 IRP

The years following the previous IRP have been eventful for PNM. This section provides context for and status of key developments since 2020.

1.5.1 Progress Towards SJGS Abandonment & Replacement

In April 2020, the NMPRC approved the application to abandon the San Juan Generating Station (SJGS) by July 1, 2022 (Case No. 19-00018-UT). Retiring SJGS removes 497 MW of coal-fired capacity from service. The NMPRC approved the portfolio of resources used to replace SJGS, which comprises 650 MW of solar PV, 300 MW of storage, 24 MW of demand response, and approximately 15 MW of additional energy efficiency (Case No.19-00195-UT). The replacement resources ordered by the NMPRC are summarized in Table 6.

Table 6. Replacement resources for SJGS ordered by the NMPRC

Plant	Plant Name	Capacity (MW)	Storage Volume (MWh)	Commercial Operation Date (Original)	Commercial Operation Date (Current)
Arroyo	Solar	300	-	6/30/2022	7/21/2023[A]
	Storage	150	600	6/30/2022	12/31/2023
Jicarilla	Solar	50	-	11/30/2021	12/31/2023[B]
	Storage	20	80	11/30/2021	8/6/2023
Rockmont	Solar	100	-	6/30/2022	--[C]
	Storage	30	120	6/30/2022	--[C]
San Juan	Solar	200	-	6/10/2022	5/31/2024
	Storage	100	400	6/10/2022	5/31/2024
Demand Response[D]		24	-	*See Note D*	
Energy Efficiency[D]		15	-		

Table Notes

A. The Arroyo Solar Project is being brought into service in a staged manner. The first 135 MW of capacity were brought online in mid-2023, and the full plant is expected to be in service by the end of 2023.

B. PNM accepted the first 25 MW of the 50 MW planned Jicarilla Solar Project on August 3, 2023. However, an inverter failure prevented the remaining capacity from becoming commercially available. Installation of the facilities is complete by COD is not expected until December 31, 2023.

C. PNM's contract with the Rockmont Solar plant was terminated after the developer defaulted.

D. In Case No 20-00218-UT, PNM issued an RFP to procure the Demand Side Management (DSM) resources, inclusive of EE. That RFP sought 24 MW of firm DR and 15 MW of either DR or EE capacity (or a combination of both) to meet the combined 39 MW of DSM requirements. PNM initially awarded a 40 MW DR contract to cover the combined requirements; however, the counterparty ultimately determined only 15 MW was available. PNM brough this 15 MW contract for new DR forward in response to the NMPRC requirements; however, that Application was denied.

Due to project delays, none of the anticipated replacement resources were able to achieve commercial operations in 2022. To ensure reliability for customers through the summer of 2022, PNM filed to temporarily extend the operation of San Juan Generating Station. To help maintain resource adequacy for the 2023 summer peak in the absence of these resources, PNM entered into multiple contracts for firm power, totaling 460 MW of firm power be available from June through August 2023 (Case No. 19-00195-UT). On February 23, 2022, the Commission approved a three-month extension of operations through September 30, 2022 (Case No. 19-00018-UT). Following this date, SJGS ceased operations as planned.

As of August 2023, the Arroyo and Jicarilla BESS projects were placed into service. The Jicarilla solar is expected to be in service by December 31, 2023. The San Juan Solar-BESS hybrid project is expected to achieve commercial operation in 2024. The developer of the Rockmont project defaulted, and this project is no longer in development.

While the demand side management resource were disapproved in Case No 20-00218-UT, there was some discussion during PMM's 2024-2026 Energy Efficiency Plan Case No 23-00138-UT and PNM will monitor the final order in that case for further direction from the NMPRC regarding the DSM resources approved as part of the San Juan abandonment.

1.5.2 PVNGS Lease Abandonment and Replacement

In addition to a 288 MW ownership share of the Palo Verde Nuclear Generating Station (PVNGS), PNM previously held leases totaling 114 MW from financial investor lessors. Under the terms of those lease agreements, there was an option to purchase the capacity at fair market value upon their expiration (104 MW on January 15, 2023, and 10 MW on January 15, 2024). In 2020, PNM announced its intention not to purchase the leased interests in PVNGS, and in 2021, filed to abandon the leases upon expiration (Case No. 21-00083-UT). On February 16, 2022, the Commission approved PNM's plans. To replace this capacity, PNM received Commission approval of 450 MW of solar PV and 290 MW of storage (Case No. 21-00215-UT). Unfortunately, the approvals came after certain regulatory end dates included in the contracts and due to supply chain disruptions, the COVID-19 pandemic, and other factors, counterparties sought to modify terms and conditions including price and deliverability terms. Ultimately, PNM was only able to renegotiate agreements with one of the three counterparties that PNM believed would be in the public interest. Due to the inability to reach mutually agreeable terms with the other two counterparties, PNM proposed, and the NMPRC approved, expanding the size of the storage component of the remaining protect to increase the amount of effective capacity, compensating for the termination of the other two projects. As approved in the amended contract, the Atrisco project will now provide 300 MW of solar and 300 MW of four-hour battery storage and is currently expected to be operational in May 2024.

1.5.3 FCPP Abandonment Application

In 2020, PNM announced a plan to transfer its 200 MW share of FCPP to the Navajo Transitional Energy Company (NTEC) at the end of 2024. On January 8, 2021, PNM filed for abandonment of its share of FCPP (Case No. 21-00017-UT), citing both economic benefits to customers and environmental benefits to the portfolio. On December 15, 2021, the NMPRC denied the application out of concern that replacement resources would not be available in time for transfer of ownership, considering delays replacing SJGS in 2022. PNM subsequently appealed this decision to the New Mexico Supreme Court, where the Supreme Court upheld the NMPRC's decision.

For this IRP PNM assumes that FCPP will remain in the portfolio through the end of the current operating agreement and coal supply contract in 2031. However, PNM is committed to moving to a carbon free portfolio and therefore will continue explore early exit benefits before 2031 to best position the company's decision for customers.

1.5.4 2026 Request for Proposals

In November 2022, PNM issued an all-source RFP for new resources capable of coming online between 2026 and 2028. Having experienced record peak demands in the summer 2022 and in anticipation of continued load growth due to strong economic growth in the region, PNM issued this RFP proactively to procure up to 1,000 MW of accredited capacity that would both support its transition towards a carbon-free portfolio and support system reliability needs.

In recognition of the delays experienced by multiple projects in recent RFPs and because of the importance of bringing new capacity resources onto the system for reliability needs, the 2026 RFP included additional requirements for projects to receive consideration. By requiring bidders to provide additional documentation demonstrating that potential resources could achieve commercial operations by guaranteed start dates specified by the RFP, PNM sought to increase confidence that new resources would be in service prior to the point in time at which they are needed for reliability. Requirements included, but were not limited to:

- Having submitted an application into PNM's Generator Interconnection Queue in Cluster 13 or earlier;
- Providing confirmation that the project schedule could be satisfied with regulatory approval occurring as late as June 30, 2024;
- Showing proof of ownership of the required land or a negotiated contract for the leasing or purchase of the required land; and
- Showing proof that all National Environmental Policy Act (NEPA) permitting, approval from the applicable federal agency, or approval from a tribal authority is completed and in-hand.

The RFP resulted in selection of five projects: one power purchase agreement, three energy storage agreements, and one engineering, procurement, and construction contract for a utility-owned storage project.

Table 7. Resources procured in the 2026 RFP

Project	Type	Capacity (MW)	Storage Volume (MWh)	Expected Commercial Operation Date
Quail Ranch	Solar	100	-	11/2/2025
	Storage	100	400	11/2/2025
Route 66	Storage	50	200	2/1/2026
Sky Ranch	Storage	100	400	2/1/2026
Sandia	Storage	60	240	5/1/2026

1.5.5 "Wired for the Future" and Grid Modernization

As one part of PNM's efforts to provide quality service, PNM announced the "Wired for the Future" initiative in 2020 with three goals: (1) enhancing customer satisfaction, (2) delivering clean energy, and (3) increasing grid resilience.

PNM also filed its Grid Modernization Plan in October 2022 (Case No. 22-00058-UT), seeking to invest $344 Million over a six-year period, funded through a modest charge, and enable customers to take greater control over their bills, and improve service. PNM requested NMPRC approval by July 2023, however, the matter is still pending.

Affordability and improved transparency of costs are key to the plan, and it will empower customers to understand and adapt their energy usage patterns through Advanced Metering Infrastructure (AMI). When paired with new energy management platforms, AMI allows customers to view their energy use patterns and adjust them to reduce their bill. For example, customer enrolled in Time-of-Use (TOU) rate plans can see their consumption patterns and associated costs; consequently, customers are empowered to shift their energy use to off-peak times, thereby saving money. PNM intends to prioritize low-income communities as AMI deployment AMI and other upgrades are made to the grid.

PNM's plan would convert a traditional "one-way" grid that delivers energy from generators to load centers, to a "two-way" distribution grid where customers are active participants. This transition comes at a time when customers demonstrate increased interest in self-generation and electrification, both of which benefit from a modern grid. New loads and resources will be connected to existing distribution networks, which were not necessarily built with behind-the-meter (BTM) generation, electric vehicles, and electric heating in mind. This contrasts with the historic trend where new loads come from new customers, being connected via new distribution lines. Technologies like AMI support the two-way grid as customers integrate BTM solar and storage with new electric loads. This allows PNM to maintain system balance by leveraging insight into real-time grid conditions that AMI provides.

PNM will also improve its reliability and resilience by hardening the distribution system, with a combination of cybersecurity and physical improvements like remote fault indicators. Remote fault indicators work with smart meters to reduce the duration and scale of power disruptions. Today, PNM is not able to remotely sense many customer outages, rather awareness is provided by customer reports. With modern technology, PNM Operators will be instantly notified of customer interruptions, thereby reducing crew response times. Remote fault indicators also enable isolation of the outage location, which allows for uninterrupted service to customers elsewhere on the system.

The Grid Modernization Plan is the first step in a long-term commitment to improving customer service. PNM anticipates filing additional stages of the plan to continually provide customers with the most up-to-date grid as the energy transition unfolds.

2 Planning Landscape

Chapter Highlights

- The 2023 IRP is set against a backdrop of rapid industry change, creating a challenging and uncertain environment for resource planning.
- Federal and state policy will continue to be a major driving force that will shape resource plans. At the federal level, the recent landmark Inflation Reduction Act (IRA) is poised to have a major role in reshaping the technology landscape through the tax incentives and loan guarantees it provides; at the state level, the Energy Transition Act and other supporting policies will continue to have major impacts on portfolio planning.
- As changes to loads and resources have shifted reliability risks in many parts of the country, the industry has continued to prepare for a future with large amounts of variable resources and uncertain weather events driven by climate change.
- As these same trends impact prices and energy availability in wholesale markets, there is increasing interest in organized regional markets in the western interconnection.
- Multiple noteworthy trends in technology are incorporated into PNM's plan. While the costs of many generation technologies have increased due to supply chain constraints, inflationary pressures, and rising interest rates, other emerging technology options have come closer to commercialization, bolstered by private sector investments and new opportunities created by the IRA.

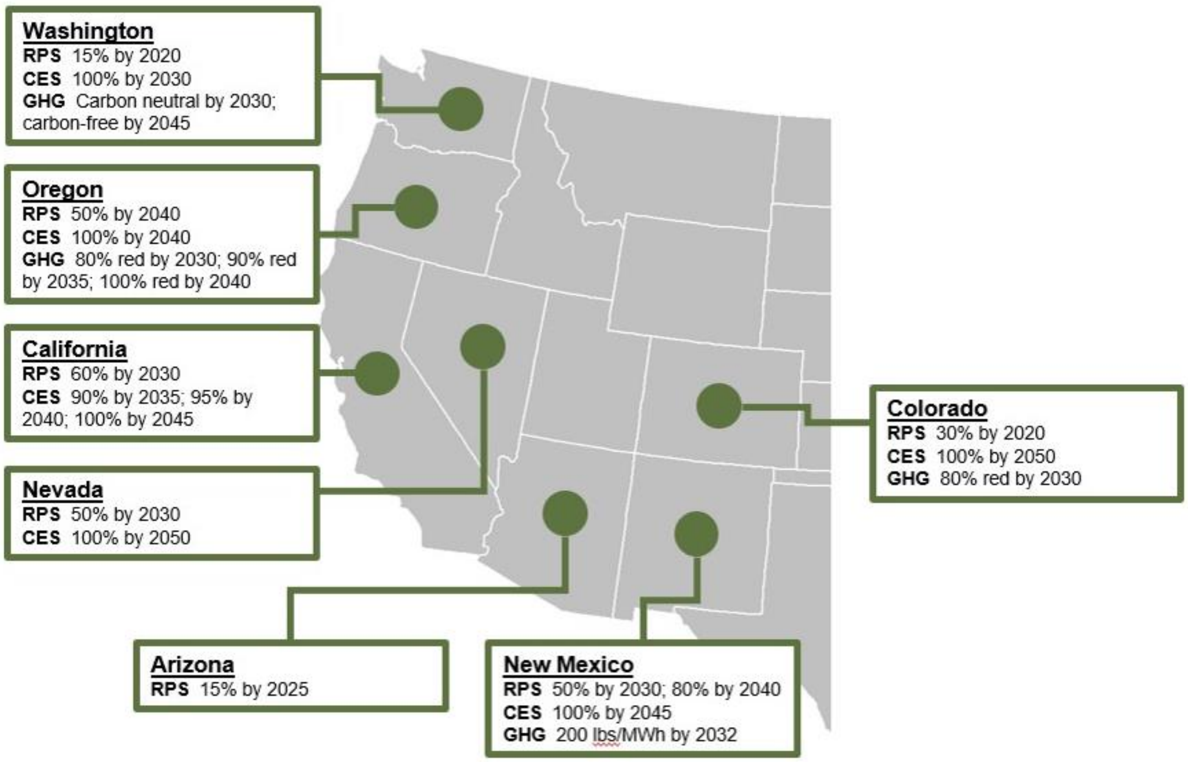
The pace of change within the industry and the corresponding uncertainties and challenges it creates for the planning process were important themes in PNM's last IRP; change and uncertainty continue to be important factors that shape this IRP. Some of these changes reflect a continuation of trends observed in the last plan – for instance, the mounting concern surrounding increasing reliability risks – while others have fundamentally altered the planning landscape – for example, the passage of the Inflation Reduction Act (IRA). Concurrent with the industry's rapid evolution, PNM's own system is poised to undergo massive changes as it progresses towards carbon-free goals. This section explores some of the key industry trends and forces that will shape PNM's near- and long-term plans.

2.1 Key State & Federal Energy Policies

The future of the electric industry is increasingly shaped by clean energy policy and regulation at the local, state, and federal level. The most notable political development since PNM's last IRP in 2020, was the passage of the federal IRA in 2022. The IRA established a broad economic stimulus through tax credits and loan guarantees for a wide array of carbon-free energy resources and associated infrastructure. While the full effects of these stimuli have yet to manifest in the markets, PNM is hopeful that the federal tax benefits made available will help accelerate progress towards its carbon-free objectives, while limiting the cost impacts to customers.

At the same time, state and local policies and voluntary clean energy commitments continue to drive the clean energy transition. Many western states have established aggressive clean energy and decarbonization goals for the electric sector that require timely investments in new renewable and energy storage resources. These policies and the corresponding changes in the regional resource mix in the coming decades have direct and significant implications for a utility like PNM that operates within the Western Interconnection. Increasing development of variable renewables and energy storage – favored over conventional firm fossil-fueled generators – will impact how and when the region experiences reliability risks (discussed in Section 2.3.2) as well as the dynamics observed in day-to-day wholesale markets.

Figure 13. Clean energy policies by state in the Western Interconnection.



State and federal energy policies are also poised to reshape the electricity industry in New Mexico. The following section discusses the key policies that play a major role in shaping the future plan, including the IRA, the ETA, as well as PNM's own commitment to clean energy, and other regulatory and policy obligations.

2.1.1 The IRA

In August 2022, President Biden signed the IRA into law. The Act directs an estimated $370 billion in new federal spending to support greenhouse gas emissions reductions across the energy and industrial sectors. The clean energy and climate provisions deliver funding through a mix of tax incentives, grants, and loan guarantees. An estimated $216 billion of energy and climate funding is in the form of tax credits, intended to promote private investment in clean energy, transportation, and manufacturing. The IRA allocates over $45 billion for environmental justice priorities and stipulates equity impacts be demonstrated for many funding opportunities.

Clean Electricity Tax Credits

The most significant provisions of the IRA that will directly impact PNM's future resource planning and procurement efforts are the extensions of the federal Investment Tax Credit (ITC) and Production Tax Credit (PTC). The IRA makes several significant modifications to the previously legislated tax credits, which were previously scheduled to ramp down and expire in the mid-2020s:

- **Extension of the ITC and PTC:** The IRA extends the ITC and PTC through the later of (a) 2032 or (b) the point in time when the greenhouse gas emissions from the electric sector in the United States have been reduced by 75% relative to 2005 levels. Because industry experts do not expect the United States to achieve this level of decarbonization before 2032, it is likely that the tax credits will remain in effect throughout most, if not all, of the 20-year planning horizon.

- **Expanded Eligibility:** Starting in 2025, the IRA expands eligibility of the tax credits to a broader set of technologies. Any resource that produces carbon-free energy is eligible to claim the PTC, and the ITC can be claimed by generation and storage resources.

- **Multiple Tiers of Credits:** The IRA establishes multiple levels of potential tax credits, which vary according to the location and types of labor and materials used to develop a project:

    - All eligible technologies can claim a “base” credit ($5/MWh for PTC or 6% for ITC);
    - This credit can be multiplied by a factor of five for projects that meet prevailing wage and apprenticeship requirements ($26/MWh for PTC and 30% for ITC);
    - Three additional bonus credits can further increase the value of credits by 10% each, applicable to projects that meet conditions for (1) domestically produced content such as steel and iron, (2) location in a low-income community, and (3) location in an “energy community”. These bonus credits may be additive.

Energy Communities

One of the more important provisions in the IRA for future procurements is the bonus credit for projects located in an “energy community.” Subsequent guidance from the Treasury Department and the Internal Revenue Service establishes three categories of such communities:

- Any census tract (or directly adjoining census tract) where a coal mine closed after 1999 or a coal-fired generator closed after 2009;

- Any metropolitan statistical area or non-metropolitan statistical area that has an unemployment rate above the national average and exceeds either a threshold for direct employment relating to fossil fuel extraction, transport, and/or storage industries (0.17%) or a threshold for local tax revenues from fossil fuel extraction, transport, and/or storage (25%).

- Brownfield sites as defined in the Comprehensive Environmental Response, Compensation, and Liability Act of 1980.

Significant portions of the state of New Mexico are likely to qualify as energy communities according to the first two criteria (see Figure 14).

Figure 14. Locations in New Mexico that currently meet requirements to qualify for as an energy community under the Inflation Reduction Act

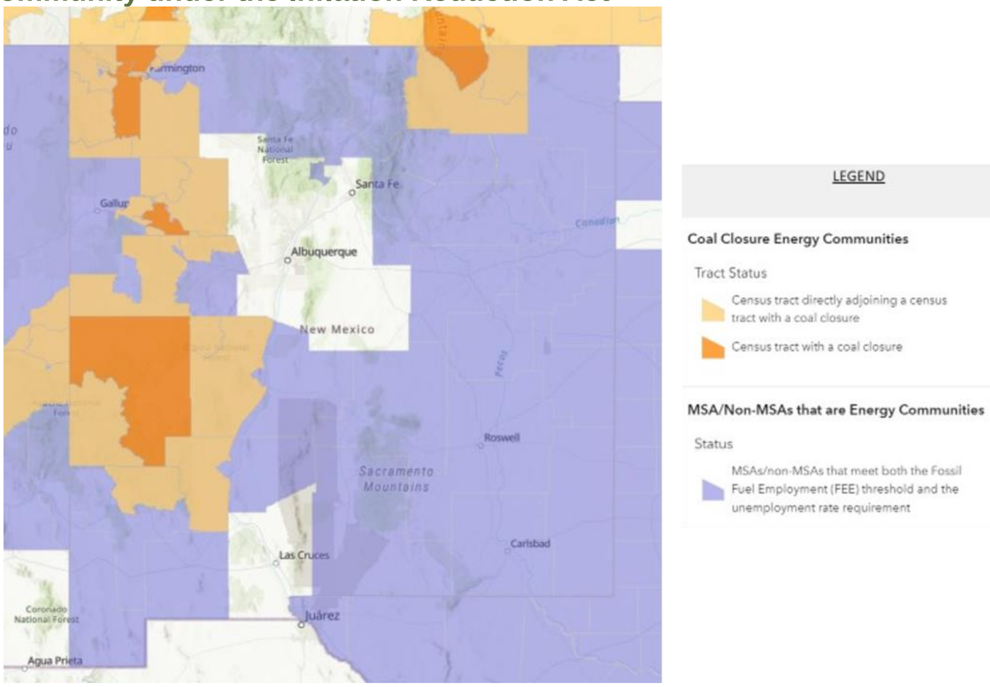


Image adapted from:
https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d

Stakeholder Input: Focus on Procurement in Energy Communities

Many of the stakeholders emphasized the importance of considerations relating to equity, just transition, and support for disadvantaged communities, as well as leveraging federal subsidies. While the long-term planning conducted in the IRP does not include geographic specificity that would allow for consideration of this bonus credit, PNM plans to proactively seek such opportunities. The combination of bonus tax credits will benefit customers and the ability to work with and support communities historically dependent on fossil fuel industries create a strong alignment of incentives for PNM to give strong consideration to the geographic focus of its procurement activities.

Additional Opportunities Created by IRA

Several other provisions of the IRA also present opportunities that PNM's plans will consider:

- **PTC for Existing Nuclear Generators (45U):** A separate PTC is established for existing nuclear generators, which can be applied to PNM's share of PVNGS.
- **Tax Credits for Hydrogen Production (45V):** The IRA introduces a PTC for hydrogen production, with the credit level determined by the embedded carbon intensity of the fuel. For "green" hydrogen produced via electrolysis fueled by carbon-free energy, this credit can be as high as $3/kg. This credit has a ten-year lifetime and can be claimed by any resource that commences construction before 2033.

- **Tax Credit for Captured and Sequestered Carbon Dioxide (45Q):** The IRA provides a tax credit of up to $85/ton for generators that capture and sequester carbon dioxide. This credit has a twelve-year lifetime and is available to resources that commence construction before 2033.

- **Financing Support for New Transmission Lines:** The U.S. Department of Energy can now provide loans to support the development of new transmission lines, facilitating the interconnection of renewable resources to the grid. These loans may reduce the cost of financing investments in transmission, making it easier to scale up renewable generation.

- **Incentives for Electrification and Energy Efficiency:** The IRA offers additional credits to incentivize transportation and building electrification, as well as energy efficiency in buildings. These incentives aim to drive changes on the demand-side and contribute to economy-wide decarbonization efforts.

The IRA could have major implications for PNM on both the demand-side and supply-side. Higher electric loads will require PNM to procure additional resources to maintain reliable service. The ITC and PTC, however, will make these resources less expensive, especially wind, solar, and storage. Transmission financing may allow interconnection and delivery of more high-quality, low-cost renewable resources to the system, further improving affordability.

While the IRA offers promising prospects for advancing clean energy, PNM acknowledges that its impact on emerging technologies, such as hydrogen, remains uncertain. As tax credits begin to expire in the 2030s, PNM must carefully evaluate which emerging technologies to deploy in the medium-term to fully capitalize on the benefits provided by the IRA and achieve the 2040 carbon-free goal.

Overall, the IRA represents a significant opportunity for PNM to bolster its commitment to clean energy and align resource planning with the evolving landscape of federal policies and incentives. PNM is optimistic that the IRA's provisions will enable substantial progress towards its ambitious clean energy goals and contribute to a more sustainable and environmentally friendly energy future for customers and communities.

The Infrastructure Investment and Jobs Act (IIJA) allocates an additional $100 billion to the energy sector. The IIJA can support PNM’s efforts to modernize the grid with funding in smart grid technology, cybersecurity, distribution hardening, and infrastructure that supports electric vehicles. Additionally, the IIJA supports efforts to site and build new transmission lines. PNM may also benefit from IIJA investments for developing emerging, low-cost renewable technologies. This includes targeted funding for technologies, including energy storage, carbon capture, and hydrogen fuel.

2.1.2 The ETA and PNM’s Decarbonization Goals

In 2019, lawmakers passed New Mexico’s ETA, a landmark piece of legislation establishing a bold vision for the state’s energy supply. This piece of legislation continues to provide a strong direction for future planning, having established a comprehensive energy policy for New Mexico electric utilities that provides for the orderly transition of the state's electricity supply needs away from fossil fuel generation to carbon-free sources of energy. The key components of the ETA are:

- **The creation of a framework for utilities to transition away from coal-fired generation to lower carbon resources.** To encourage a transition away from reliance on coal generation, the ETA established mechanisms that allowed utilities filing for abandonment of existing coal plants to securitize any remaining undepreciated investment, and to recover the costs related to decommissioning and workforce transition, by issuing energy transition bonds. Any utility that issues energy transition bonds must also comply with carbon intensity standards of 400 lbs/MWh by 2023 and 200 lbs/MWh by 2032.

- **Support for communities impacted by coal retirements.** The ETA also provides for economic support for the communities that will be most directly impacted by the closure of coal plants. This includes the creation and administration by the state of the Displaced Worker Assistance Fund and Economic Development Assistance Fund to support workforce training and local economic development, as well as a requirement that up to 450 MW of the replacement resources for SJGS be located in the Central Consolidated School District in San Juan County.

- **An increase to the state's current Renewable Portfolio Standard.** Under the ETA's amendments to the Renewable Energy Act,[2] utilities in the state must comply with RPS targets of 40% by 2025, 50% by 2030, and 80% by 2040.[3] The establishment of these aggressive targets and interim milestones provides a clear signal to the electric industry of the level of renewable development that will be needed within the state over the next two decades.

- **The establishment of a state goal to achieve a carbon emissions-free generation portfolio by 2045.** The ETA's final legislative contribution is the creation of an ultimate target for the state to eliminate greenhouse gas emissions entirely from its utilities' portfolios by 2045. The legislation also specifies that "reasonable and consistent progress shall be made over time toward this requirement". In establishing this goal, the ETA made New Mexico one of the first states to commit to eliminating carbon emissions from electricity generation within this timeframe.

PNM supports the vision set forth by the ETA and has already undertaken steps to achieve it. The ETA's provisions encouraging timely abandonment of coal plants allowed for abandonment of SJGS by 2022; many of the resources procured to replace it reduce costs to customers and position PNM's portfolio to achieve significant near-term reductions in carbon emissions.

While the ETA requires a carbon emissions-free electricity portfolio by 2045, PNM is working towards achieving this milestone in 2040, five years sooner than required by statute. With industry advancements in the past decade and the promise of continued technological innovation, this transition is possible and will best serve the needs and preferences of customers over the next two decades.

Together, the ETA and PNM's own goals prescribe a roadmap of overlapping milestones for clean energy that guides the planning process. PNM's portfolios are designed to meet the statutory

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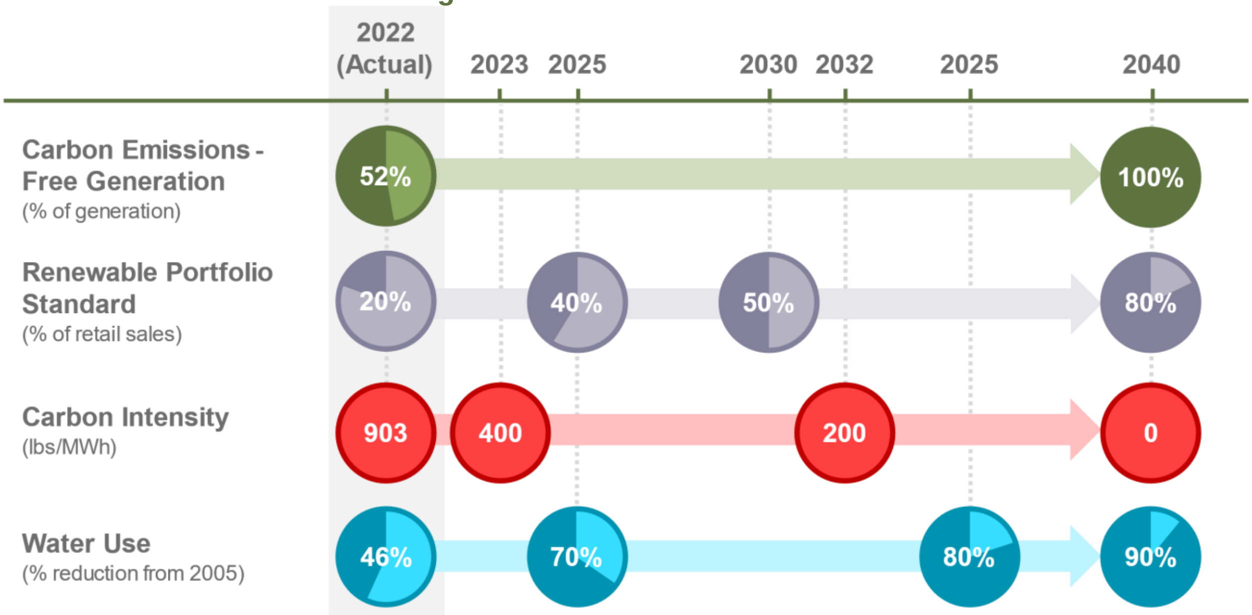
[2] New Mexico's RPS program was established with the passage of the Renewable Energy Act (SB 43) in 2004 and subsequently updated (SB 418) in 2007 to require IOUs in New Mexico to meet the following renewable procurement targets (note that RPS compliance carve-outs resulted in small deviations from these values): 5% of retail sales by 2006, 10% by 2011, 15% by 2015, and 20% by 2020.

[3] Renewable resources whose output is earmarked for PNM Solar Direct and Sky Blue ®, as well as renewables directly contracted to large customers, are not eligible to count towards RPS compliance requirements. As a result, the actual penetration of renewable resources in the system portfolio exceeds the reported values in PNM's RPS compliance reports.

requirements prescribed by the ETA while also transitioning towards a 100% carbon emissions-free portfolio by 2040. Figure 15. Timing of key portfolio milestones in the planning horizon Figure 15highlights the key milestones considered in the planning process on the pathway to a carbon emissions-free portfolio.

Figure 15. Timing of key portfolio milestones in the planning horizon as stated across the ETA and PNM's environmental goals



2.1.3 New Mexico State Greenhouse Gas Reduction Goals

In 2017, the United States withdrew its support from the Paris Agreement, a multinational agreement among more than 190 countries committing to greenhouse gas reductions. Shortly thereafter in response, governors from several states established the U.S. Climate Alliance, a bipartisan coalition of governors committed to reducing greenhouse gas emissions through action at the state level. In 2019, New Mexico's governor enacted Executive Order 2019-003, joining the U.S. Climate Alliance in support of the Paris Agreement and establishing New Mexico's first formal goal to reduce economy-wide emissions by 45% by 2030 (relative to 2005 levels). In 2021, the United States renewed its commitment to the Paris Agreement, further signaling the national priority to reduce greenhouse gas emissions.

While New Mexico's state greenhouse gas reduction goals and its support of the Paris Agreement do not establish any formal requirements for future resource plan(s), each influence PNM's philosophy, approach, and priorities within the process:

- First, these commitments underscore the importance of the ETA and the pledge to achieve a 100% carbon-free portfolio. As the largest electric utility within the state of New Mexico, PNM serves approximately 36% of the state's retail load. PNM's 2005 emissions of 7.7 million short tons represent a significant portion of the state's historical 2005 baseline. Meeting aggressive decarbonization targets will invariably require significant direct emissions reductions in the resource portfolio. PNM's current plans expect to reduce emissions by over 80% relative to 2005 levels by 2030.

- Second, New Mexico's commitment to a carbon-free economy may eventually lead to an increased role for PNM as an electric utility. Many studies of economy-wide decarbonization highlight transportation and building electrification as core to a successful transition strategy. While these measures can reduce emissions across the economy, they will require electric utilities like PNM to take on an even more central role in the decarbonization effort by supplying low or zero carbon electricity to an increasingly broad selection of end uses. At the time of this plan, there is little existing direct policy support for electrification in New Mexico, so this plan currently reflects a moderate level of electrification. However, PNM also recognizes that future policies implemented to enable the state's progress towards its goal may result in increases in new types of electric loads that will present both new opportunities and challenges.

2.2 Technology Trends

One of the foremost challenges involved with integrated resource planning is developing long-term solutions in the presence of significant uncertainties. This is particularly acute today, as PNM navigates a diverse and rapidly changing array of technologies on its pathway toward decarbonization.

Identifying the various sources of uncertainty and how they affect planning decisions is a crucial part of ensuring the resulting plan is robust and resilient. Enumerating these uncertainties and risks better prepares PNM to design a flexible portfolio that: (1) meets the near-term needs of customers at reasonable costs, (2) enables material progress towards decarbonization goals, and (3) allows optionality to adapt and take advantage of future opportunities.

2.2.1 Renewables & Storage Development

In the past decade, solar photovoltaic and wind energy resources have emerged as mature, cost-competitive options for carbon-free, renewable energy. This maturation led to a rapid pace of additions, with solar and wind each adding roughly 10 GW of capacity per year since 2020.[4] By the start of 2023, the total installed capacity of utility-scale solar photovoltaic resources across the country exceeded 60 GW;[5] Figure 16 shows the extent of these installations across the country.

The rapid ascendence of both technologies has been enabled by substantial declines in cost and technological improvements in the past decade. Between 2009-2019, the median capital cost of utility-scale solar PV installations declined by 70% in real terms, while capacity factors increased due to more frequent use of tracking technologies and higher inverter loading ratios. From 2010 through 2020, the average capital cost of new wind projects decreased by roughly 50%, while turbine designs with larger rotors and higher hub heights have led to improvements in performance.

[4] Lawrence Berkeley National Laboratory (LBNL), *Land-Based Wind Market Report: 2023 Edition*, available at: https://www.energy.gov/eere/wind/wind-market-reports-2023-edition
[5] LBNL, *Utility-Scale Solar, 2023 Edition*, available at: https://emp.lbl.gov/utility-scale-solar

Figure 16. Development of new utility-scale wind and solar resources development through 2022.

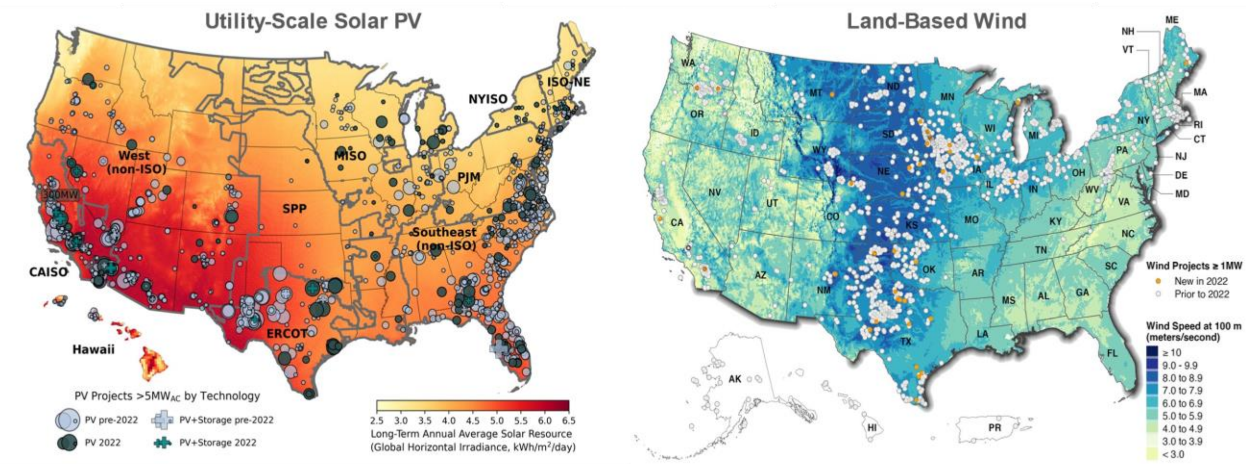


Image sources: (1) LBNL, *Utility-Scale Solar, 2023 Edition*, available at: https://emp.lbl.gov/utility-scale-solar; (2) LBNL, *Land-Based Wind Market Report: 2023 Edition*, available at: https://www.energy.gov/eere/wind/wind-market-reports-2023-edition

Similarly, development of battery storage for grid balancing and reliability continues to accelerate. At the time PNM's 2020 IRP was published, the total amount of grid-scale storage in the United States was approximately 1,500 MW. Since that time, deployment of storage has accelerated rapidly, and the U.S. Energy Information Administration (EIA) projections indicate that total installed capacity could exceed 30,000 MW nationally by the end of 2024.[6]

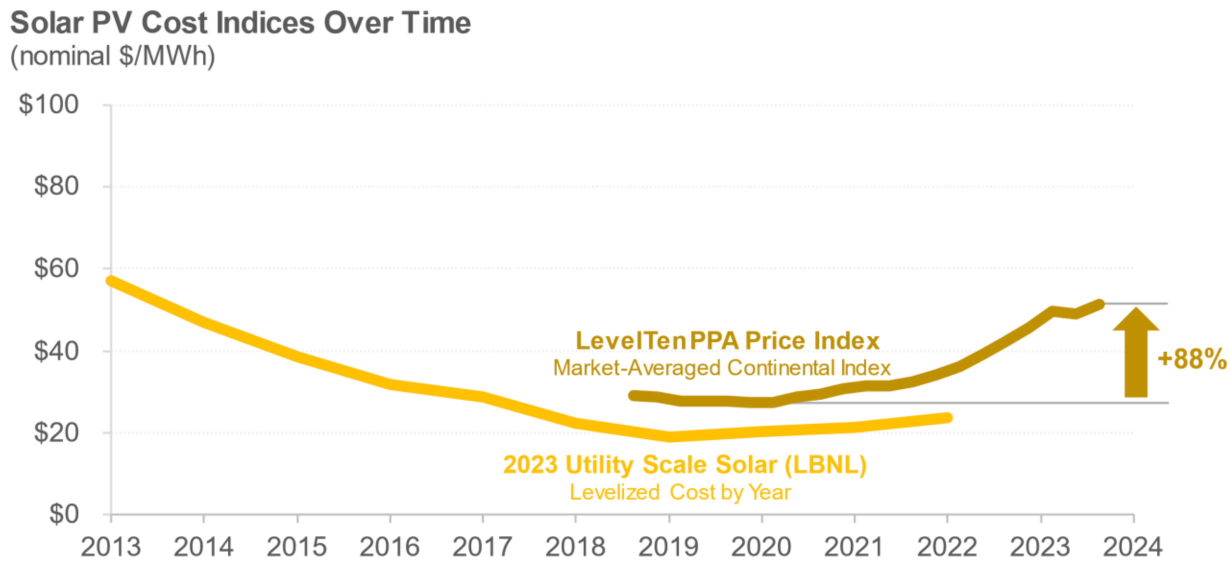
These trends are indicative of the increasingly central role that renewable and storage resources will play in meeting energy needs, both nationally and locally, within PNM's system. At the same time, the past several years have also been challenging for new resource development. Understanding the potential volatility of the resource development landscape and acknowledging future uncertainties is crucial to developing a robust IRP framework and the transition to a carbon-free portfolio.

Rising Technology Costs

After more than a decade of sustained cost reductions through 2020, solar and wind costs have experienced material increases in the past several years. Figure 17 summarizes solar cost indices reported by two reputable sources: the annually published *Utility Scale Solar* report authored by the Lawrence Berkeley National Laboratory and the quarterly PPA Price Index released by LevelTen Energy. Notwithstanding differences in the absolute level, the two series convey a similar picture of the industry reaching a low watermark for pricing between 2019-2020 and experiencing cost increases thereafter. From its lowest point in 2020, the national LevelTen PPA index for solar has increased by 88%. The most recent data, published more than a year after the passage of the IRA, continue to show high costs, signaling limited relief in pricing increases in the near term despite the newly available tax credits.

[6] EIA, "Battery Storage in the United States: An Update on Market Trends," available at: https://www.eia.gov/analysis/studies/electricity/batterystorage/

Figure 17. Observed changes in solar costs over the past decade



Battery storage resources have faced similar upward pressure on pricing in recent years. Public data on actual project costs is not as readily available as for wind and solar; however, PNM has experienced these conditions directly, recently renegotiating the San Juan ESA at a price 24% above the original contract price.

The rising costs observed across the industry are the result of multiple contributing factors:

- **Continued disruptions in global supply chains:** most of the world's solar and battery components are manufactured in China, ranging from 40% to 97% depending on the component. China also accounts for 60% of processed metals that are used in wind, solar, and storage technologies. This triggered global challenges during the COVID-19 pandemic when most factories in China shut down. On top of this, decreased fuel supply during the pandemic increased transportation costs for renewable developers. Manufacturing outside of China was also impacted by constrained supplies for critical metals that make up solar panels, wind turbines, and batteries.
- **Inflationary pressure:** rising inflation rates in the past several years have caused increases in the costs of raw materials and labor, which in turn impacts costs to develop new infrastructure projects.
- **Rising interest rates:** in an effort to slow inflation, the US Federal Reserve has progressively increased interest rates over the past few years. This has the effect of increasing the costs to finance new generation projects. Because renewables and storage are capital-intensive projects (compared to traditional fossil generators), the increased cost of financing has an outsize effect on the cost of these new technologies.
- **Increasing demand for renewables and storage:** clean energy policies at federal, state, and local levels have continued to drive increased interest in development of clean resources; meanwhile, recent volatility and high prices in fossil fuel markets have further spurred demand. This higher level of demand has in turn exacerbated already constrained supply chains.

Higher development costs will directly impact PNM's long-term resource plans. PNM will continue to seek out near-term opportunities to source affordable, clean energy; in the long term, PNM recognizes the wide cone of uncertainty around technology costs and will consider key sensitivities around long-term technology cost reductions in its IRP process. This proactive approach to the planning process enables PNM to anticipate possible market conditions and recognize indicators and signposts that may prompt necessary adaptations.

Project Delays & Cancellations

The conditions that contributed to recent cost increases have also led to more project delays and cancellations. In 2022, EIA reported that nearly 20% of all solar projects under development had experienced some form of delay, with similar trends observed for other resources as well.[7] PNM has experienced these delays in projects coinciding with the closure of San Juan Generating Station, the impending expiration of PNM's leases in Palo Verde Nuclear Generating Station, and plan to withdraw from Four Corners Power Plant.

In the 2020 IRP, PNM outlined a plan to fully divest from its coal-fired resources by 2025 and invest in clean energy, storage, and demand-side measures to decarbonize its energy supply. PNM remains committed to the transition away from fossil generation, but must account for increased levels of uncertainty in project development timelines for replacement resources. In recent years, energy suppliers and developers have canceled or delayed new power projects across the globe; PNM experienced these conditions firsthand when it learned that new solar and storage resources, which were expected to be online by spring 2022, would be delayed beyond that summer. With limited notice, PNM subsequently issued an expedited RFP for short-term firm resources and new clean energy resources. Ultimately, PNM delayed the retirement of SJGS by several months to ensure reliability during the summer peak season. As these dynamic supply chain conditions persist, PNM must continue to adapt to mitigate risks.

Real-World Performance Data from Grid-Scale Batteries

Despite its rapid growth, the real-world operational history of grid-scale battery storage is relatively short; uncertainties involving how rates of degradation and other performance factors might deviate from planning assumptions remain.

Nonetheless, real-world performance data can be used to inform improvements in long-term planning. As an example, Figure 18 summarizes historical outage rates for battery storage resources currently operational in California, based on data published by the California Independent System Operator. The rate of forced outages, which exceeds 10% across all storage resources, is higher than most manufacturers' specifications for expected outage rates. These figures also inform how PNM characterizes the probability of outages for battery storage in the IRP.

[7] EIA, *Today in Energy: Utility-scale solar projects report delays,* available at: https://www.eia.gov/todayinenergy/detail.php?id=53400

Figure 18. Analysis of battery storage outage rates observed in California

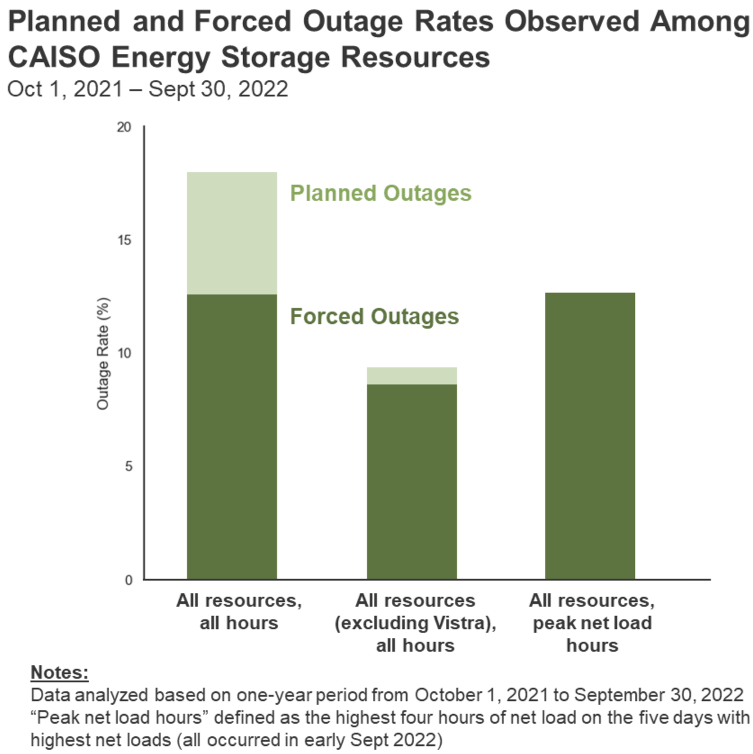


Image adapted from E3 presentation to Arizona Public Service Resource Planning Advisory Council, available at: https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS-RPAC-Meeting-Presentation-102622.ashx?la=en&hash=9AE20E699D178AFCF8AB30BF9C64FFED

The misalignment of planning assumptions and real-world experience is an inherent risk associated with the integration of emerging technologies. Over time, such risks can be mitigated as engineers and operators gain more experience and planning studies can incorporate additional real-world operating data. PNM will continue to monitor storage performance in the market and calibrate its planning tools to the best and most recent operational experience to improve related assumptions in future IRPs.

2.2.2 Emerging Technology Evolution

Bolstered by infusions of capital from the private sector and the allocation of significant federal funding through the IRA and IIJA, research, development, and deployment activities focused on bringing new technologies to market are accelerating. Recognizing the challenges ahead on the path towards a carbon free future, PNM is actively monitoring the evolving technology landscape. Advancements in technology will provide new opportunities to adapt the resource portfolio and meet the needs of customers at the lowest cost.

Since the passage of the IRA, interest in a particular subset of emerging technologies has swelled – so-called "clean firm resources," whose critical role in enabling the final transition to a carbon-free electricity system is increasingly well understood. This category of resources is broad, comprising advanced nuclear generation technologies, renewably fueled thermal generators, long duration storage (LDES), and carbon capture and sequestration (CCS). The opportunities to bring each of these technologies to market in the next decade has been articulated by the US Department of Energy's "Pathways to Commercial Liftoff" project – a series of reports intended to provide the industry with perspective on what would be needed for each technology to mature to commercial readiness. These reports provide a useful indication of the current state of technology readiness and the possible timeframes upon which deployment at commercial scale may be viable, which, in turn, helps to shape PNM's own assessment of opportunities.

Figure 19. Long duration storage technologies characterized in US Department of Energy's *Pathways to Commercial Liftoff: Long Duration Energy Storage*[8]

NON-EXHAUSTIVE – HYDROGEN AND HYBRID LONG DURATION STORAGE EXCLUDE

Faces geologic constraints[4] | Not enough public datapoints to obtain a reliable value | Less Desirable – More Desirable

Inter-day | Can function as both | Multi-day/week

Duration	Energy storage form	Technology	Nominal duration, hrs	LCOS[5], $/MWh	Min. deployment size, MW	Average RTE, %	TRL
Inter-day	Mechanical	Traditional pumped hydro (PSH)	0–15	70–170	200 – 400	70–80	9
		Novel pumped hydro (PSH)	0–15	70–170	10–100	50–80	5-8
		Gravity-based	0–15	90–120	20–1,000	70–90	6-8
		Compressed air (CAES)	6–24	80–150	200–500	40–70	7-9
		Liquid air (LAES)[1]	10–25	175–300	50–100	40–70	6-9
		Liquid CO_2[1]	4–24	50–60	10–500	70–80	4-6
Multi-day / week	Thermal	Sensible heat (e.g., molten salts, rock material, concrete)[2]	10-200[2]	300	10–500	55–90	6-9
		Latent heat (e.g., aluminum alloy)	25–100	300	10–100	20–50	3-5
		Thermochemical heat (e.g., zeolites, silica gel)	XX	XX	XX	XX	XX
	Electrochemical	Aqueous electrolyte flow batteries	25–100	100-140	10–100	50–80	4-9
		Metal anode batteries	50–200	100	10–100	40–70	4-9
		Hybrid flow battery, with liquid electrolyte and metal anode (some are Inter-day)[2,3]	8–50[2]	XX	>100	55–75	4-9

2.2.3 PNM's 2022 Technology RFI

As part of ongoing efforts to monitor changes in the technology landscape, PNM periodically issues requests for information (RFI), soliciting information from potential developers on technology options that may help contribute to meeting future resource needs. In preparation for this IRP, PNM issued two technology-focused RFI in 2022, seeking market intelligence in two areas:

1. **Future Resources:** projects with a longer development lead-time that could bridge the gap between near-term RFP responses and post 2030 emerging technologies with an approximate timeframe of 2025-2030
2. **Emerging Technologies:** technologies that can help meet PNM's decarbonization goal and that can be fully deployed after 2030 and beyond

Key Terms *A **Request for Information (RFI)** is a process in which a utility issues a solicitation to project developers to provide information on potential new resources with the purpose of gathering market intelligence. In contrast, a **Request for Proposals (RFP)** is a process in which a utility issues a solicitation to developers to provide competitive bids for potential resources that will be evaluated by the utility to fill a specified procurement need.*

RFIs specifically asked for information related to potential resources, including but not limited to:

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[8] Image source: US Department of Energy, *Pathways to Commercial Liftoff: Long Duration Energy Storage*, available at: https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-LDES-vPUB.pdf

- General information regarding the characteristics of the technology;
- Operating characteristics, including performance (e.g. nameplate capacity, ramp rates) and costs (e.g. capital, operations and maintenance);
- "Technology Readiness Level" (TRL), as measured on a scale from 1 (basic principles developed) through 9 (commercially available and operational) developed by Sandia National Laboratory; and
- Information related to software capabilities to support system operations.

The two solicitations produced 26 total responses to help inform resource planning. The responses provided by developers included information on future generation resources, transmission projects that could enable delivery of new resources to loads, and software and services engineered to help utilities optimize the energy system. The responses to the Future Resources and Emerging Technologies RFIs are summarized in Table 8 and Table 9, respectively.

Table 8. Responses to PNM's technology RFI for future resources

Respondent	Technology	Project Description
Black Forest Partners	Transmission	Double circuit high voltage transmission line connecting Afton, NM to Tucson, AZ; fully permitted with estimated operational date Q4 2027.
CSOL Power LLC	Thermal storage	Underground thermal storage that stores a high temperature (650 C) using geomaterials (such as basalt and quartzite gravel, or fabricated refractory materials); facility will use blown air to transfer heat to steam generator for use in a pre-existing steam turbine
EDF Renewables	Solar PV & Energy Storage	Three new large scale solar hybrid/battery projects located in southwestern US
Engie Renewables	Solar PV & Energy Storage	Three new large scale solar hybrid/battery projects
Grid United LLC	Transmission	High voltage direct current transmission line
K-TEK International	Parts fabrication, service provider	K-Tek is a single point of contact for field service and engineering services, and a range of product supply capabilities including HRSG/boiler pressure and non-pressure parts, burners, igniters, flame scanners, controls, valves, pumps, fans, blowers, NOx catalysts, etc.
Kinetic Power	Pumped Hydro Storage	New pumped storage project (1,500 MW, 70 hours of duration) near Four Corners
Morse Associates, Inc.	Concentrated Solar Power	Molten-salt tower with thermal energy storage, projects sized at 90-180 MW depending on configuration with 12-16 hours of energy storage
ReneSola Power	Solar PV	Utility-scale generating capability from solar array and battery storage
rPlus Hydro LLP	Pumped Hydro Storage	A 600 MW closed-loop pumped hydroelectric storage facility located at a site in San Juan County
Uplight Inc	Software/service	Software solutions & platform provides DR, energy efficiency, and active TOU rate management, and includes tools for both residential demand and EV load shifting
Wallis Energy Corporation	Pumped Hydro Storage	600 MW pumped storage project located in Arizona and New Mexico on tribal land

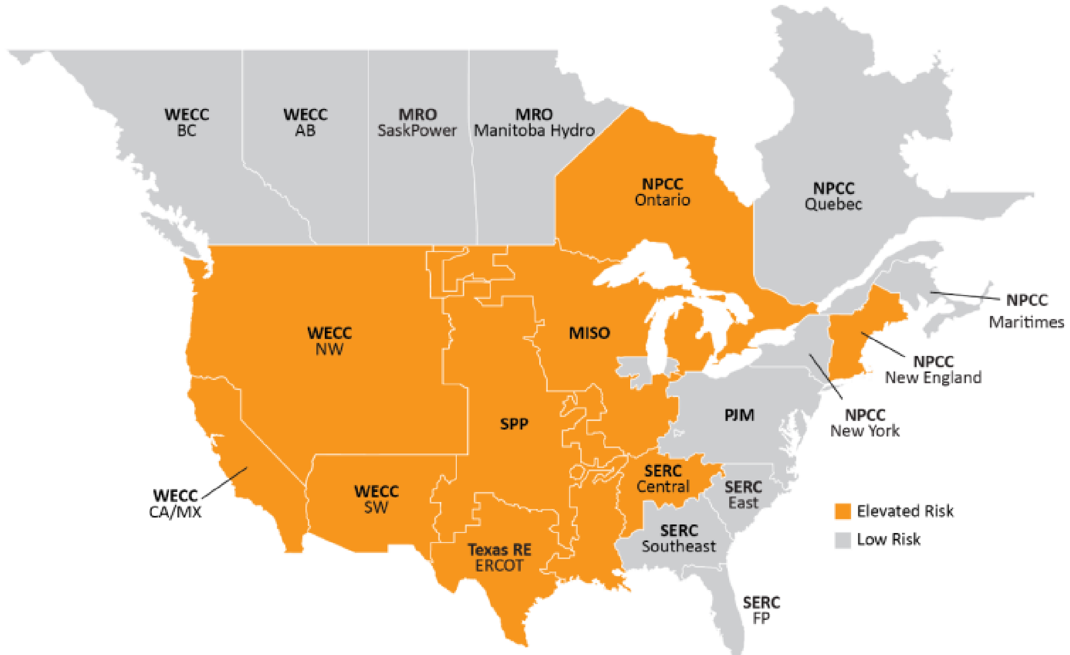
Table 9. Responses to PNM's Technology RFI for emerging technologies

Respondent	Technology	Project Description
Aequatis Energy Solutions	Hydrogen	Hydrogen created using excess renewable energy (minimal information provided)
Coyote Clean Power	Natural Gas with Carbon Capture & Sequestration	A 280 MW combined cycle plant utilizing advanced/norel supercritical CO2 power cycle. The design is based on the NET power system, which combusts fuel with oxygen and uses supercritical CO2 as a working fluid to drive a turbine (instead of steam).
EDF Renewable	Hydrogen	Green H2 production for PNM's fossil fired generating stations
Escalante H2 Power LLC	Hydrogen	Proposes retrofit of Escalante Generating Station to use blue/green hydrogen (utilizes carbon-capture technology for blue hydrogen production; uses renewables to produce green hydrogen)
Form Energy	Iron-air Energy Storage	Energy storage with ~100 hour duration using reversible rusting process: when discharging, battery cycle breathes in oxygen from air to convert iron metal to rust; when charging, the process is reversed when an electrical current converts the rust back to iron
Plus Power, LLC	Iron-air Energy Storage	Energy storage with ~100 hour duration using reversible rusting process: when discharging, battery cycle breathes in oxygen from air to convert iron metal to rust; when charging, the process is reversed when an electrical current converts the rust back to iron
Mainspring Energy	Linear Generator	Generator units that uses low temperature reaction of air and fuel to drive magnets through copper coils to efficiently produce energy; fully dispatchable technology with fuel flexibility (allows seamless switch between natural gas, biogas, hydrogen, and other fuels); modular technology installed in 250kW increments
Motor EV LLC	Software/Service	Consumer electric vehicle adoption platform designed to improve EV adoption rates; can implement utility-preferred EV rate or managed charging programs
NextEra 360	Software/Service	Software designed to forecast and model market conditions, predict and optimize asset performance to make utility operations more efficient
Wallis Energy Corporation	Geothermal	Uses new drilling techniques to provide steam for use in: (a) existing coal or other steam electric plants, (b) a tolling agreement to provide steam, or (c) the purchase of existing assets to sell power to PNM using steam produced through these methods

2.3 Evolving Reliability Challenges

One of the more important recent developments in the industry over the past several years has been the increasing challenges to plan and operate a reliable, resilient electric grid. NERC's most recent summer assessment characterizes most of the continental United States as subject to "elevated" reliability risks (see Figure 20) in the coming summer.

Figure 20. NERC 2023 Summary Reliability Assessment summary



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Image sources: NERC 2023 Summer Reliability Assessment, available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf

The presence of elevated reliability risks in the southwestern United States is affirmed by several other recent studies of resource adequacy, including WECC's *Western Assessment of Resource Adequacy* and E3's *Resource Adequacy in the Desert Southwest*.[9] These studies provide additional insights into the challenges facing the region.

- In 2022, E3's *Resource Adequacy in the Desert Southwest* study identified multiple challenges toward maintaining reliability in the region: load growth coupled with increased reliance on non-firm resources, the increasing likelihood of extreme weather events, and increased scarcity in wholesale markets.

> "In a system that is already close to load-resource balance in 2021, the compound effect of [load growth and resource retirements] – plus the potential effects of increased drought risk on hydro production – create a total need for new effective capacity of roughly 5,000 MW. Resources under development today, which comprise a mix of solar, storage, wind, and natural gas, are together capable of meeting a portion – but not all – of this deficit… In a system that is already on the cusp of an acceptable level of reliability today, the ability of the region's utilities to preserve reliability over the next few years will depend on their success in bringing new resources online in a timely manner to address this shortfall."

– E3, *Resource Adequacy in the Desert Southwest*

[9] E3, *Resource Adequacy in the Desert Southwest*, available at: https://www.ethree.com/wp-content/uploads/2022/02/E3_SW_Resource_Adequacy_Final_Report_FINAL.pdf (this study was sponsored by a group of six southwestern utilities that included PNM).

- In 2022, WECC's *Western Assessment of Resource Adequacy* identified similar trends, including supply chain-driven delays in bringing new resources online. As a result, WECC projects an increasing risk to reliability throughout the Western Interconnection from 2025 onward.[10]

> ***Key Term***
>
> ***Non-firm resources*** *are resources with limited capability to dispatch on demand, including variable renewable resources (e.g. solar and wind) and resources with limits on length of dispatch (e.g. energy storage)*

The rising prominence of this risk across large parts of the country has brought significant attention to this topic and highlighted challenges facing the industry. Real-world load shedding events such as those observed in California (August 2020) and Texas (February 2021) have been the subject of intense scrutiny in efforts to discern what lessons may be learned by the industry. The topic of resource adequacy has received increased attention from expert researchers such as the Energy Systems Integration Group (ESIG), which has recently published an important series of whitepapers on reliability planning for the future.

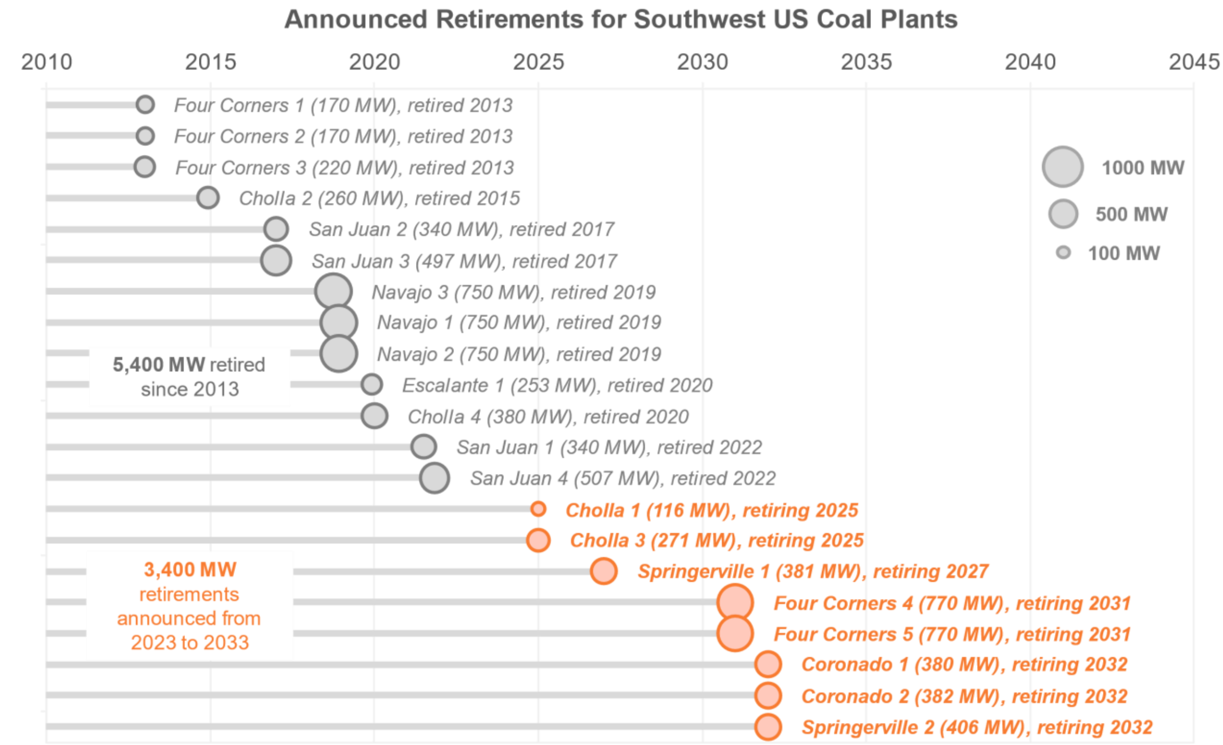
Planning and operating a reliable electric system to meet customers' needs has always been a priority for PNM and a key objective of the IRP process. Understanding the factors contributing to these growing reliability challenges and how they are continuing to evolve over time helps PNM ensure that its planning practices remain consistent with industry best practice and helps to situate its own efforts to plan a reliable system in the context of trends underway across the industry. This section discusses a number of the industry trends and recent insights relevant to this topic; how these factors are incorporated into PNM's own reliability planning is discussed in Sections **5.2.1** and **5.2.4**.

2.3.1 Retirement of Aging Baseload Resources

One of the most significant factors contributing to tightening reserve margins within the region is the retirement of aging baseload generators; primarily coal-fired resources. Retirements are the result of several factors: plants approaching the end of their useful lives, state and utility clean energy goals, and increasing availability of low-cost alternatives as options for replacement. In the past ten years, over 5,000 MW of coal-fired generating resources have retired in the Southwest region, and over 3,000 MW of additional retirements have been announced in the coming decade (see Figure 21). These retirements are generally moving the Southwest from a position of surplus generation capacity to a very tight load-resource balance. The 2020 IRP identified the shrinking regional reserve margin as a key trend to consider in planning. Since then, increasing load growth and additional announcements of plant closures have accelerated this trend further.

[10] Western Electric Coordinating Council, *2022 Western Assessment of Resource Adequacy,* available at: 2022 Western Assessment of Resource Adequacy.pdf (wecc.org).

Figure 21. Timing of historical and announced coal plant retirements in the Southwest region



Plant capacities based on summer ratings as reported in EIA Form 860. Retirement dates compiled from current utility plans.

2.3.2 Shifting Reliability Risks

Challenges to system reliability are also evolving as the resource mix changes. Historically, reliability planning focused on ensuring sufficient capability to meet demand during peak periods. Rapid increases in the penetrations of solar and wind generation across the region are causing the periods of highest reliability risk to shift into the "net peak" period which typically occurs during the evening hours during or after sunset.

> ***Key Term*** ***Net peak demand*** *(or simply "net peak") refers to the period when electricity demand net of output from variable renewable sources (e.g. wind and solar) is highest. This concept has been introduced as a heuristic to identify the periods when generation supply is likely to be most constrained.*

One of the most concrete examples of this phenomenon occurred in August 2020, when California experienced rotating outages on consecutive days (and utilities in other parts of the Western Interconnection issues Energy Emergency Alerts due to constrained conditions) during the middle of a west-wide heat wave. Because of the relatively high penetration of solar generation in the California system, these outages occurred later in the day than the traditional peak period. The root cause analysis published jointly by the California Independent System Operator (CAISO), the California Public Utilities Commission, and the California Energy Commission, which examined the factors that contributed to the outage events in August, called for the need to consider the impact of growing renewables in California's resource adequacy planning by planning for reliability needs across all hours of the year – but most importantly, during the net peak period.

Figure 22. Snapshot of California ISO operations on August 14, 2020

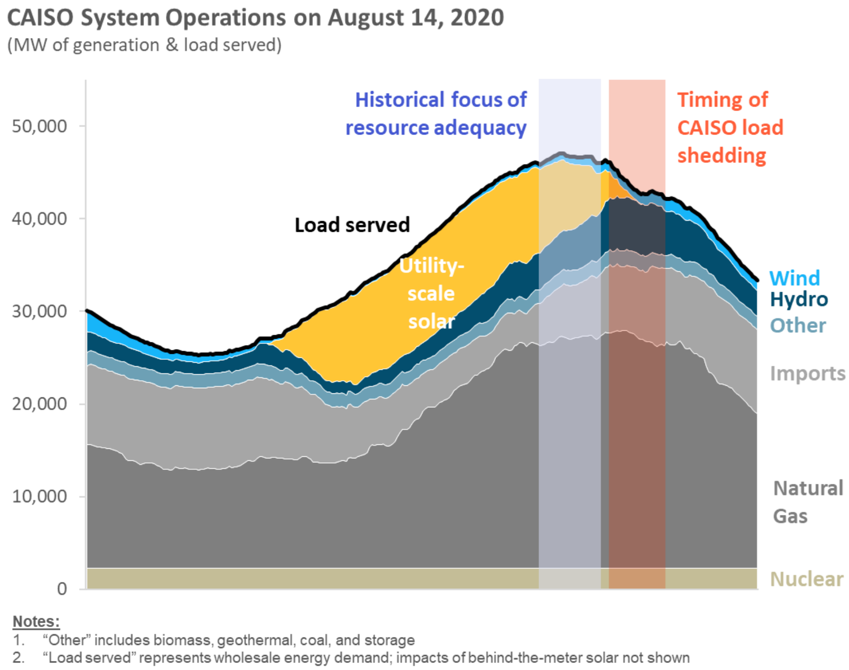


Image source: E3, *Resource Adequacy in the Desert Southwest*.

Evidence suggests that the southwestern region is experiencing a similar shift in the timing of the reliability risk profile. Research published by E3 in its study of resource adequacy in the southwest region indicates that across Arizona and New Mexico, the aggregate resource plans of the region's utilities include enough solar resources to shift the region's tightest hours of supply into the evening net peak by 2025 – and eventually, farther into the evening. This continued shift of risk is illustrated in Figure 23.

Figure 23. The shift of reliability risk to later hours of the day as southwestern utilities continue to add solar and energy storage

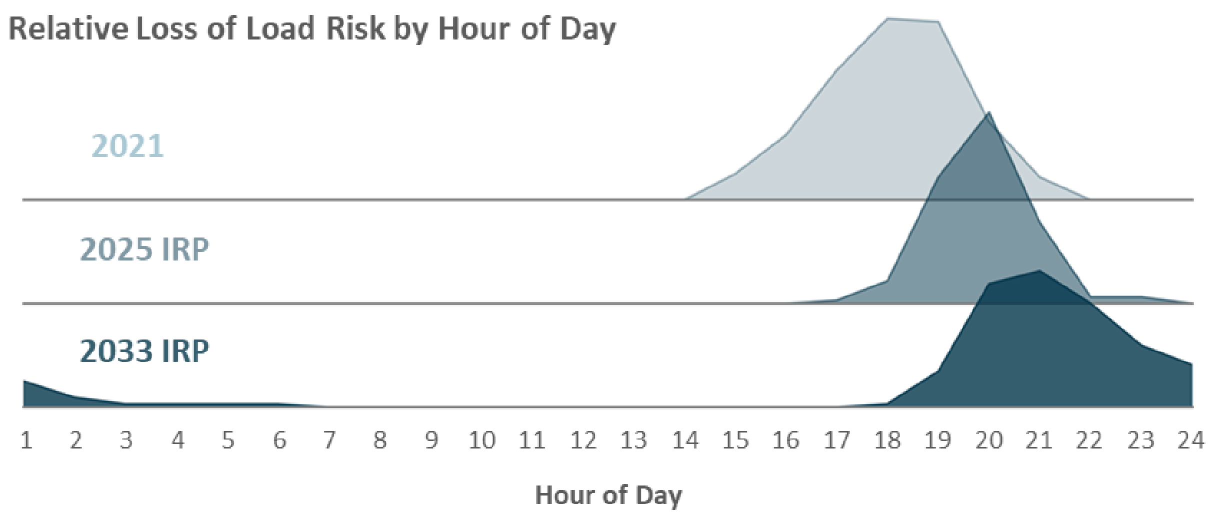


Image source: E3, *Resource Adequacy in the Desert Southwest*.

PNM identified this same shifting risk within its own portfolio in the 2020 IRP, noting that "the addition of wind and solar resources to the portfolio causes the timing of reliability needs to shift due to the changing shape of the 'net load…' By 2023, with the significant amount of new solar added as part of the San Juan replacement portfolio, the net peak will have shifted into the evening hours when solar no longer produces." The LOLP analysis conducted in that plan showed that by 2025, over 90% of the loss of load risk would be concentrated in hours after sunset.

These dynamics highlight the importance of a resource adequacy planning paradigm that accounts for risks that may occur at all times of the year and not only during the historical peak period. Best practices to consider these risks in utility planning are continuing to evolve, but broad consensus exists that a robust approach must evaluate the possibility that load shedding due to insufficient resources could occur throughout the year. As described in a recent whitepaper published by the ESIG:

> Modeling sequential grid operations is critical to capture the whole picture: the variability of wind and solar resources along with the energy limitations of storage and load flexibility. Chronological stochastic analysis is thus increasingly important, simulating a full hour-to-hour dispatch of the system's resources for an entire year of operation across many different weather patterns, load profiles, and random outage draws.
>
> – ESIG, *Redefining Resource Adequacy*

This line of thinking has heavily influenced PNM's continued efforts to refine its reliability planning approaches over the past several IRP cycles. Consistent with recommendations from ESIG and WECC, PNM continues to work to integrate LOLP modeling into its portfolio planning process to quantify how the portfolio performs across the full range of conditions throughout the year. The methods for developing a portfolio that meets these objectives for reliability while accounting for risks that may manifest throughout the year are described further in Section 5.2.1.

2.3.3 Resource Adequacy Under Deep Decarbonization

While maintaining reliability for customers in the near term is a foremost priority, PNM also orients its planning processes around the transition to a reliable electricity system that is ultimately wholly carbon free. PNM's 2020 IRP included detailed LOLP modeling of a select number of portfolios in snapshot years of 2025 and 2040, showing that those portfolios were able to maintain a Loss of Load Expectation (LOLE) standard of fewer than 0.2 days per year ("one day in five years"), even as the portfolio transitioned to carbon-free resources. The question of what is needed to ensure reliability in a carbon-free electricity system has been the subject of considerable industry research. Since the publication of the 2020 IRP, several other studies have explored the nature of these challenges:

- *Clean Firm Power is the Key to California's Carbon-Free Energy Future*, jointly sponsored by the Environmental Defense Fund and Clean Air Task Force ("EDF/CATF study");[11]
- *The Moonshot 100% Clean Electricity Study: Assessing the Tradeoffs Among Clean Portfolios with a PNM Case Study*, led by GridLab ("GridLab study");[12]

[11] Available at: https://issues.org/california-decarbonizing-power-wind-solar-nuclear-gas/
[12] GridLab, *The Moonshot 100% Clean Electricity Study: Assessing the Tradeoffs Among Clean Portfolios with a PNM Case Study,* available at: https://gridlab.org/wp-content/uploads/2023/08/GridLab_Moonshot-Study_Report.pdf

- *LA100: The Los Angeles 100% Renewable Energy Study*, led by the National Renewable Energy Laboratory (NREL) ("LA100 study");[13]

These studies collectively highlight two common findings regarding resource adequacy challenges in a decarbonized grid, the second of which is a corollary to the first:

1. At high penetrations of wind and solar generation, the greatest reliability risks occur during **sustained periods of low renewable production** (possibly lasting days to weeks); these events tend to occur in winter months, even when demand for electricity may be lower.
2. To ensure reliability even during these extended periods of low renewable production, some form of **firm generating resource** (a resource capable of generating at full capacity over sustained periods of time) is needed as a complement to renewable and short-duration storage resources.

Because of its focus on the PNM system, the GridLab study provides a particularly useful reference for the IRP. The GridLab study uses both long-term capacity expansion and loss-of-load-probability modeling to design and evaluate a range of portfolios that achieve a 100% carbon-free electricity portfolio. In its key findings, this study notes that "[t]he 'last mile' to achieving 100% clean is uncertain in terms of the cost-optimal resource mix, but clean firm resources are beneficial for the last 5-10% of energy," and elaborates with further description on the critical role that those firm resources play in a decarbonized portfolio:

> Although winter demand is low relative to summer demand, there are sustained multi-day periods where solar and wind resources cannot fully meet load, even with battery storage. During this period, low levels of wind and solar in neighboring regions limits clean imports, except during mid-day hours when solar is highest. In these conditions, hydrogen CTs or alternative clean firm resources are required to meet demand.
>
> –*The Moonshot 100% Clean Electricity Study*, GridLab

Such an event is illustrated in Figure 24, reproduced from the GridLab study based on its authors' analysis. This weeklong snapshot is characteristic of a period of relatively low renewable production that requires a firm resource (in this case, hydrogen-fueled combustion turbines) to operate during the overnight periods when the amount of energy stored in batteries is insufficient to meet loads.

[13] NREL, *LA100: The Los Angeles 100% Renewable Energy Study*, available at: https://www.nrel.gov/docs/fy21osti/79444-ES.pdf

Figure 24. Snapshot of PNM system operations over a "challenging winter week" as modeled in GridLab study

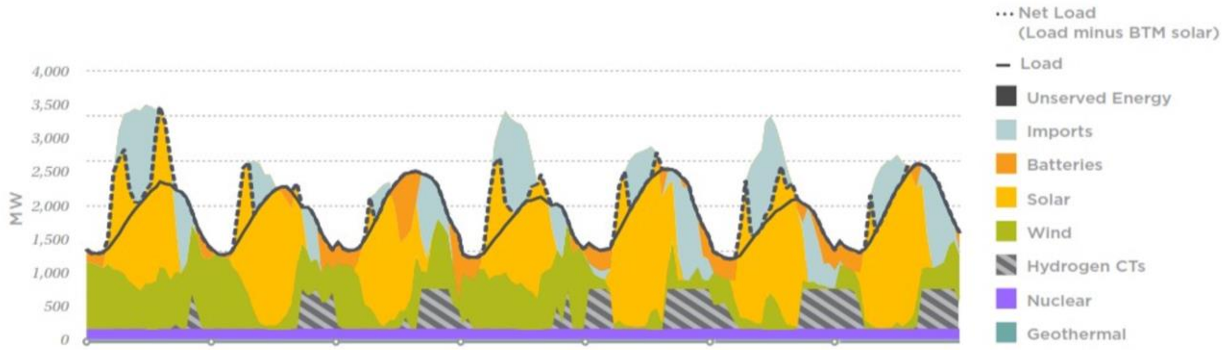


Image source: GridLab, *The Moonshot 100% Clean Electricity Study: Assessing the Tradeoffs Among Clean Portfolios with a PNM Case Study*.

The analysis conducted in the EDF/CATF study supports a similar conclusion, as the authors note that "…squeezing out the last increments of carbon from power generation while maintaining affordability and reliability will require clean firm power." Similarly, NREL's analysis in the LA100 study leads to a conclusion that "[n]ew in-basin renewable firm capacity – resources that use renewably produced and storable fuels, can come online within minutes, and can run for hours to days – is a key element of maintaining reliability at least cost…"[14]

While each electricity system is unique, this growing body of research generally affirms the notion that a transition to a wholly carbon-free electricity system will require firm resources to complement high penetrations of wind, solar, and energy storage.

2.3.4 Climate Change and Extreme Weather

Climate change has become a major source of uncertainty in planning assumptions, with immediate implications for reliability. As a summer-peaking utility, the highest energy demands occur during scorching hot days when customers rely heavily on air conditioning. More frequent and extreme hot summer weather conditions mean higher forecasted loads.

In addition to a general warming trend, climate change contributes to an increase in the frequency and intensity of extreme weather events, encompassing not only heatwaves but also cold snaps and major storms. To maintain reliability, it is vital to account for climate considerations not just in the median load forecast, but also in assessing potential loads during extreme weather occurrences. This ensures that PNM secures sufficient resources to meet customers' needs during challenging times. Analyzing weather conditions where wind and solar output may be low becomes crucial to ensure a consistent power supply even in adverse conditions. Further, climate change threatens to exacerbate the extant scarcity of water resources in the Southwest. In addition to its fundamental importance for sustaining life and habitability, freshwater directly supports the energy sector in applications including power plant cooling and – in the future – as an input to electrolysis for hydrogen production.

The importance of safeguarding against resource insufficiency during extreme weather is underscored by notable events over the past three years, which have had significant impacts on the electric system. For instance, the 2020 West-wide heatwave led to rotating outages in

[14] NREL, *LA100: The Los Angeles 100% Renewable Energy Study.*

California, the 2021 winter storm resulted in multi-day blackouts in Texas, and a 2022 heat wave across the West nearly pushed the system over its limits. These incidents serve as stark reminders of the potential risks utilities face and reinforce the need for proactive planning to address the implications of a changing climate on reliability.

Understanding the potential effects of a changing climate on loads and resources necessitates ongoing efforts and a continuous commitment to study evolving trends. PNM acknowledges that incorporating climate change into the planning processes requires a dynamic and adaptive approach. These steps can strengthen resilience and readiness to face the challenges posed by climate change, ensuring a reliable and sustainable energy future for PNM's customers and communities.

2.3.5 Resilience vs. Resource Adequacy

There is no single, widely adopted industry definition of grid resilience. However, many definitions focus upon a system's ability to withstand, mitigate negative impacts, and rapidly recover from disruptive events. FERC has proposed a definition resilience as the "the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[15]

PNM uses definitions from the resilience study, *Toward a Consensus on the Definition and Taxonomy of Power System Resilience,*[16] which characterizes potential outage events in the following ways:

1. **Known events:** Conditions for which enough historical data is available that it is possible to reasonably estimate the odds of these conditions occurring. There is also enough historic data of grid performance during these conditions that these can be considered "normal" operating conditions. These are already directly captured in Resource Adequacy studies completed in PNM's IRP process.
2. **Gray swan events:** Weather conditions whose nature can be predicted based on some occurrences from the past or with future projections, but the data is too sparse to reasonably estimate their odds.
3. **Black swan events:** Black swan conditions, by definition, cannot be predicted. These are conditions for which odds and the nature of the events cannot be estimated.

These categorizations clarify how resource adequacy differs from resilience. Resource adequacy modeling focuses upon known events that can be characterized probabilistically, planning for system operations under a wide range of conditions with a quantifiable statistical likelihood. These events are modeled in SERVM through historical weather and load data development. As the climate changes, the unknown likelihood of extreme events occurring in the region forces PNM to look beyond the known events. The study of resilience focuses upon how the system performs during "abnormal" conditions representing gray swan or black swan events. These events do not occur often enough to understand their frequency of occurrence yet could be disruptive to customers.

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[15] Grid Resilience in Regional Transmission Organizations and Independent System Operators, Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61, 012 at P 23 (January 8, 2018).

[16] Gholami A, Shekari T, Amirioun MH, Aminifar F, Amini MH, Sargolzaei A. Toward a Consensus on the Definition and Taxonomy of Power System Resilience. IEEE Access. 2018;6:32035-32053. doi:10.1109/ACCESS.2018.2845378

Lessons from PNM's 2021 Resilience Study

Following the 2020 IRP, PNM sponsored a study to examine resilience risks on its system. This study, jointly conducted by E3 and Astrapé Consulting, used the SERVM LOLP model developed in the IRP to simulate future portfolios under a range of different extreme "gray swan" conditions to explore the stressors that could lead to reliability events on the system. The study conducted a wide range of stress tests on portfolios designed to meet a common LOLE standard of 0.2 days per year under specific extreme weather events in both summer and winter. The lessons learned from this study, summarized in Table 10, improved PNM's understanding of stressors that should be considered in the current planning process.

Table 10. Integration of key lessons from the resilience study into the current planning process.

Resilience Study Finding	Reflection in PNM's Current IRP
Different resource portfolios that meet the same LOLE planning standard exhibit varying performance during extreme events.	While PNM plans its portfolios to target a specific LOLE standard, it includes alternative reliability metrics (expected unserved energy, loss of load hours) as evaluation criteria (see Section 7.3.5).
Stress testing candidate portfolios for resilience can help identify differences in their performance.	As a final step in the portfolio evaluation process, PNM reproduces several of the "stress tests" created in the resilience study and tests portfolios under those specific events (see Section 7.3.6).
Weatherization of all generation resources to allow for performance under extreme conditions provides additional resilience.	Cost assumptions for all new resources are intended to reflect necessary weatherization measures.
Firm generation resources reduce the severity of extreme event impacts in both summer and winter.	The IRP evaluates an expansive range of firm resource options, including emerging technologies not previously considered in the IRP (see Sections 6.3 and 6.4).
Broader southwest dynamics will have significant impact on PNM's ability to avoid outages under winter extreme events.	For the LOLP analysis, PNM and Astrapé have updated the representation of neighboring electric systems to capture more realistic expected future changes in loads and resources (see Section 5.2.1)
As PNM expands its energy storage portfolio, its operational limits and utilization should be understood and considered in resource adequacy modeling.	PNM incorporates a forced outage rate for battery storage into its reliability modeling that is consistent with actual performance data (see Section 6.3.1).

2.4 Wholesale Market Opportunities & Risks

The Western Interconnection has not organized into a Regional Transmission Operator model or an Integrated System Operator approach and as such, the Interconnection exists today as a patchwork of Balancing Authorities and utilities, many of which have historically planned and operated their systems independently except for long-term contracting and bilateral wholesale trading of energy. Many studies have highlighted the fragmentation of the Western Interconnection as a potential barrier to achieving high penetrations of renewable generation. They have further highlighted greater regional coordination as an opportunity to reduce system costs and accelerate the transition to renewables.[17]

[17] See, for example, E3's *Western Interconnection Flexibility Assessment*, which found that "Improving regional coordination offers a low-hanging fruit among integration strategies", or Energy Strategies' *Western Flexibility Assessment*, whose observation that "In the long-term, results indicate that it will be very

PNM has traditionally owned or contracted its own resources to meet customers' demand, but during critical periods, PNM relies on power purchases from neighboring utilities. In recent years, sharing resources amongst other utilities has continued to support regional reliability. Interest continues to grow in regional marketplace(s) where utilities and other providers can buy and sell power, lending support to neighboring utilities when it is needed the most.

The Western Energy Imbalance Market (EIM) is one such organized market functioning in the west, and it has produced significant benefits for its participants to date. However, its scope is limited (intra-hour) when compared with more formal organized energy markets. Capitalizing on the success of the EIM to date, multiple utilities in the West have begun exploring the possibility of extending the same principles into the day-ahead timeframe. Market structures proposed by CAISO and the Southwest Power Pool (SPP) would allow EIM entities to expand participation into a voluntary optimized day-ahead market, enabling greater coordination in unit commitment and dispatch. These initiatives are ongoing, and PNM will continue to monitor their progress as a stakeholder.

2.4.1 Western Energy Imbalance Market

The Western Energy Imbalance Market (EIM) is an effort to promote more formal and organized coordination among the various entities of the West. This coordination harnesses the benefits the load and resource diversity across a broader geographic region, thereby reducing participants' system costs. The EIM allows utilities to exchange energy on a fifteen- and five-minute basis in an optimized manner across its footprint, enabling more efficient system dispatch and reducing curtailment of renewable resources. Since its inception in 2014, the footprint of the EIM has expanded to include large portions of the Western Interconnection, and in 2023, includes major utilities across most states in the West. To date, the EIM has produced benefits over $4 billion for its participants and is estimated to have resulted in greenhouse gas emissions reductions of 904 thousand tons due to avoided renewable curtailment.[18]

Figure 25. Western EIM footprint and market

The NMPRC approved PNM's application to join the EIM (Case No, 18-00261-UT) and submitted an order allowing potential recovery of EIM costs in future rate cases and requiring compliance reports on EIM costs and savings. PNM joined the EIM in April 2021. Since then, participation in the EIM has consistently provided substantial benefits for customers, ranging from $2 to $22

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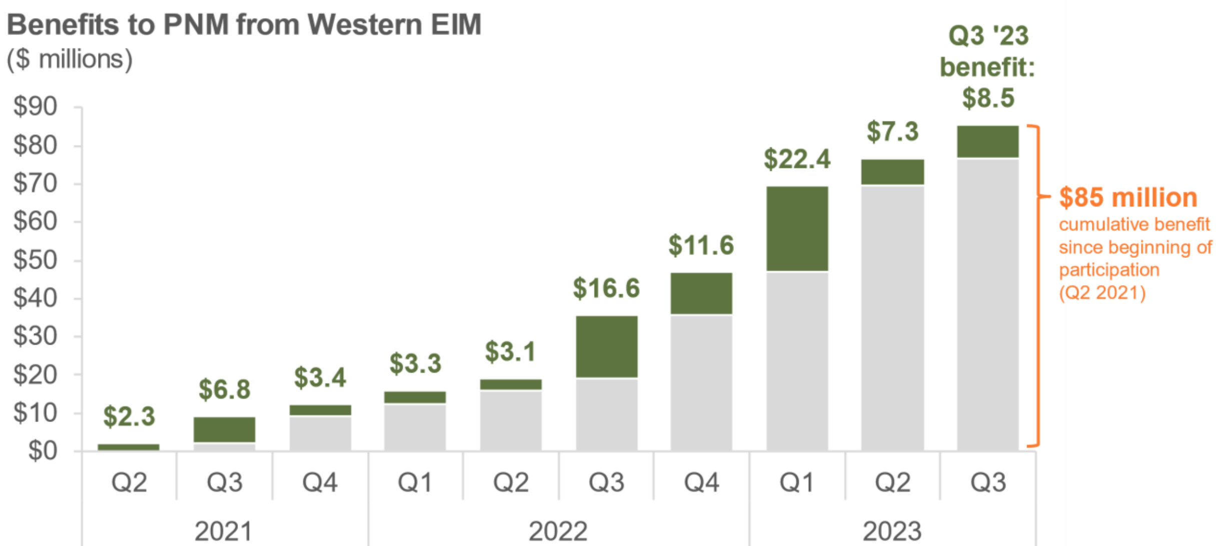
difficult, or at least extremely costly, to achieve Western policy targets without broad coordination of wholesale markets" suggests substantial benefits under high renewable penetrations.

[18] California ISO, "Western Energy Imbalance Markets Benefits Report, Third Quarter 2023." Available at: https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q3-2023.pdf

million per quarter.[19] Through the third quarter of 2023, the total estimated benefit to PNM customers from PNM's participation is $85 million (see Figure 26).

Figure 26. Cumulative economic benefits to PNM from participation in Western Energy Imbalance Market



The EIM facilitates cost savings through more efficient real-time dispatch of the resources in its footprint; these cost savings result from:

- Wholesale transactions of energy between Balancing Areas that would not have otherwise occurred in the bilateral day-ahead markets;
- Redispatch of resources to relieve transmission constraints in various parts of the system; and
- An ability for operators to carry lower quantities of operating reserves due to the diversity of loads and resources across a broader footprint.

PNM's own benefits from participation stem from a combination of these factors. One recent noteworthy market opportunity facilitated by the EIM occurred in 2022, when a severe heatwave in California resulted in tight conditions and high real-time prices in the California system. Because conditions in New Mexico were comparatively mild at the time, PNM was able to sell surplus energy its resources to sell to California, supporting the reliability of that system while earning substantial benefits for customers.

While the EIM produces savings for customers through more efficient operations of resources, it has no direct effect on PNM's resource adequacy needs. In fact, EIM entities are required to pass resource sufficiency tests for in advance of each operating hour as a prerequisite to participation to demonstrate that they are not inappropriately relying on capacity or flexibility from other EIM participants; those that cannot are excluded from the market until they can demonstrate sufficiency.

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[19] These benefits are calculated and reported quarterly by the California Independent System Operator and are available at: https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

2.4.2 Western Resource Adequacy Program (WRAP)

WRAP was created by the Northwest Power Pool, which includes utilities across nine western states and two Canadian provinces, as a regional program to improve resource adequacy. It was motivated by a large number of planned plant retirements, coupled with excessive reliance on the market to meet individual utilities' resource adequacy needs, and concerns that these conditions could lead to a regionwide capacity deficit. Since launching in September 2021, 26 utilities have joined WRAP, which currently operates as a non-binding program. In 2028, it is anticipated that the program will become binding for its participants. Should this be the case, PNM would be obligated to meet resource adequacy requirements administered by WRAP, which would replace PNM's own resource adequacy standard.

Figure 27. Current WRAP membership

PNM supports exploring options for regional markets, recognizing that coordination through the EIM has already provided benefits for PNM and across the region. Further regionalization will likely reduce costs even further and access support from neighboring utilities. PNM cannot exclusively spur the formation of a regional market but continues to monitor ongoing efforts throughout the West and communicate with neighboring utilities to determine the best path forward.

2.4.3 Western Markets Exploratory Group (WMEG)

Since the last IRP cycle, PNM, along with 13 other western utilities, began participation in another regionalization effort called the Western Markets Exploratory Group (WMEG). Participants are exploring the potential staged creation of services such as a day-ahead market, potential transmission system expansion approaches, among other priorities. WMEG participants have engaged a third-party study vendor to evaluate the potential benefits of regional market structures that will create opportunities that further support the energy transition in the West.

Both WRAP and WMEG explore the potential of sharing resources with neighboring electric providers to enhance reliability, reduce costs for customers, and help achieve carbon reduction goals together.

3 Load Forecast

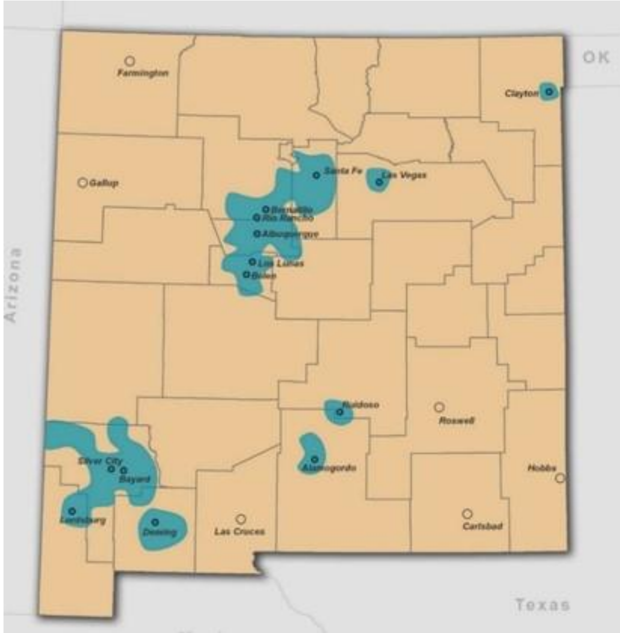
Chapter Highlights
• PNM provides retail electric service to customers throughout the state of New Mexico; customers include residential, commercial, industrial, and other end users of electricity.
• PNM tailors programs and services to meet customers' needs and preferences, which includes energy-saving measures, support for electrification, and renewable energy.
• PNM's peak demand, which is approximately 2,000 MW in 2023, is expected to grow at an average rate of 0.9% per year over the 20-year IRP horizon. This forecast reflects current expectations for economic and demographic changes, economic development projects, behind-the-meter solar adoption, and electric vehicle adoption.
• PNM's IRP includes multiple load forecast scenarios. These futures and sensitivities consider the different levels of the variables described above as well as building electrification, time-of-use rate design, and extreme weather events. In the highest load growth forecast included in the IRP, peak demand grows at a rate of 3% per year through 2042.

PNM's mission is to provide safe, reliable power to customers at affordable prices. Customer usage patterns and preferences inform resource planning and procurement decisions. As such, the MCEP identified through the portfolio analysis process in this IRP is designed to evolve in concert with customer needs and preferences over the coming years. This chapter describes PNM's customers and their energy usage, customer offerings through rates and programs, as well as the forecast for peak demand and energy use through 2042.

3.1 PNM Customers

PNM's retail service territory, shown in Figure 28, covers a large area of north central New Mexico, including the cities of Albuquerque, Rio Rancho, and Santa Fe as well as most of the area around the Rio Grande Valley from Belen to Santa Fe. Other communities in PNM's territory include Lordsburg, Silver City, Deming, Alamogordo, Ruidoso, Tularosa, Clayton, Las Vegas, several New Mexico Pueblo nations, and numerous unincorporated areas.

Figure 28. Map of PNM's electric service area



PNM's retail electricity customers number about 530,000 and include many different types of users. For the purpose of providing retail electric service, PNM organizes these customers into fourteen classes that reflect different sizes, applications, and patterns of consumption. PNM's classes of service are listed in Table 11, along with breakdowns of total customers, annual load, contribution to peak, and revenue from these classes.

Table 11. PNM's 2022 customer counts, usage, and revenue

Customer Class	Customers (#)	Annual Load (GWh)	Coincident Peak (MW)	Revenue (M$)
Residential	486,120	3,371	1,079	443
Small Power	54,636	948	219	125
General Power	4,136	1,868	408	194
Large Power	161	906	152	76
Large Service	2	57	11	5
Private Lights	0	14	0	3
Irrigation	307	20	6	2
Water and Sewer	151	176	26	12
Universities	1	67	7	5
Street Lights	192	34	0	6
Large Manufacturing	1	410	53	26
Station Power	1	4	0	0
Large Power > 3MW	3	174	28	10
Special Service Rate	1	929	83	19
Total	**545,712**	**8,978**	**2,072**	**926**

PNM customers' demand and energy usage vary based on geography, climate, customer type, and technology adoption. Accounting for these differences is important in the planning process to ensure that all customers receive the service they require.

3.2 Existing Demand-Side Programs

As enumerated in the updated IRP Rule, demand-side resources consist of two types: energy efficiency (EE) and load management. Energy efficiency refers to reductions in energy use by customers over the whole year, the timing of which is dependent on the measure. Load management programs, such as demand response (DR), reduce customer demand specifically at times of peak load or during shortages of supply. This section describes the current EE and DR programs, along with historical program performance and program descriptions in compliance with the requirements of the updated IRP Rule Section 17.7.3.9(C)(9).

PNM's existing resource portfolio includes EE and DR programs approved by the NMPRC pursuant to the Efficient Use of Energy Act (EUEA). These programs are required to pass the Utility Cost Test, which compares program costs to benefits. Benefits include avoided generation costs (e.g. fuel and emissions) along with avoided or deferred costs of capacity additions. The EUEA requires utilities to invest between 3% and 5% of retail sales revenues in energy efficiency and load management programs. Annual budgets for efficiency and demand response have grown over time, reaching $31 million in 2021.

3.2.1 Energy Efficiency

PNM's energy efficiency programs offer a diverse set of opportunities to customers to save energy, reduce their electricity bills, and benefit the environment. The programs are designed to complement supply-side planning, to meet the requires of the EUEA, and to facilitate transformation of the New Mexico economy to the public benefit. As described in the *2024 Energy Efficiency and Load Management Program Plan*:

> In addition to meeting the requirements of the Act, PNM's EE programs encourage lasting structural and behavioral changes in the New Mexico economy through the process of market transformation. This is accomplished by promoting the purchase of energy efficient products and services, increasing customer awareness of energy efficiency measures, providing incentives to change behaviors, and removing market barriers. Over time, distributors will stock more efficient equipment, contractors will promote more efficient equipment to their customers, and customers will become more inclined to purchase efficient equipment.
>
> *– 2024 Energy Efficiency and Load Management Program Plan*

PNM carefully tracks savings produced by its energy efficiency programs using the results from an annual measurement and verification process. The process is conducted by an independent third-party evaluator selected by the NMPRC and reports metrics including customer adoption rates as well as energy savings, carbon emissions reductions, and reductions in water use by generators that is attributable to PNM's EE programs. Table 12 summarizes the results of the programs from 2008 through 2022. Since 2012, efficiency programs have consistently yielded energy savings of 70 GWh per year or greater. Because these savings persist over time,[20] the total impact of the efficiency programs on load is larger still: the cumulative load reduction in 2022 was 750 GWh, which resulted in nearly 400 thousand tons of avoided greenhouse gas emissions and over 2,000 million gallons of water conserved.

The effects of these historical programs are captured directly in the load forecast. In forecasting load, programs are assumed to be replaced as they expire, so that demand and energy savings continue throughout the plan period. The load impacts of future energy efficiency programs are modeled explicitly in the IRP as a resource option; the characterization of this option is discussed in detail in Section **6.1.1**.

[20] The effective useful lifetime of the EE portfolio of measures is nine years; when calculating cumulative savings metrics, PNM only counts savings from the previous nine years for this reason.

Table 12. Historical statistics for energy efficiency program impacts

Year	Incremental Energy Savings (GWh)	Cumulative Energy Savings (GWh)	Cumulative GHG Savings (000 tons)	Cumulative Water Savings (million gal)	Peak Demand Savings (MW)	Annual Program Cost ($ millions)
2008	35	35	24	14	7.5	$8
2009	40	75	51	44	6.3	$12
2010	59	134	92	95	9.9	$17
2011	58	192	131	166	9.7	$17
2012	79	271	186	262	13.6	$17
2013	76	346	237	384	11.8	$18
2014	75	421	289	522	12.0	$22
2015	79	501	343	685	12.1	$24
2016	82	583	348	876	13.0	$26
2017	75	622	372	1,080	11.9	$26
2018	71	653	390	1,270	12.5	$23
2019	78	672	355	1,466	13.7	$24
2020	87	702	391	1,648	15.0	$26
2021	107	730	379	1,838	18.8	$30
2022	96	750	390	2,033	13.9	$31

Compliance with EUEA Targets

The EUEA and subsequent amendments have established minimum energy savings goals for energy efficiency programs. Historically, the comprehensive energy efficiency programs have surpassed the minimum standards required by the EUEA:

- The original EUEA established a 2014 goal of 5% of PNM's 2005 retail sales, or 411 GWh; PNM exceeded this goal with 421 GWh of cumulative savings;
- Amendments in 2013 established a 2020 goal of 8% of 2005 retail sales, or 658 GWh, which PNM surpassed with 702 GWh of cumulative savings; and
- The most recent amendments in 2019 established goals for 2021-2025 of 5% of 2020 retail sales, or approximately 395 GWh.

Through the end of 2022, PNM saved just over 200 GWh toward this goal, which puts PNM in a favorable position to meet or exceed this target. PNM plans to continue existing energy efficiency programs are documented in the *2024 Energy Efficiency and Load Management Program Plan*, which establishes plans for 2024-2026 that are expected to produce approximately 100 GWh of incremental savings each year. PNM expects an increase in annual program costs, as many of the supply chain disruptions that have affected other parts of the industry also have implications for program costs as well.

Program Cost Effectiveness

As specified by the EUEA, the energy efficiency programs must pass the Utility Cost Test at the portfolio level. This means that the benefits realized through avoided energy and capacity costs must exceed the costs to administer the program and provide incentives for customer adoption. Typically, the programs exceed a benefit-cost ratio of 1.0 by a significant margin: in 2022, for example, the benefit-cost ratio of the portfolio was 1.77.

Overview of Programs

PNM's energy efficiency programs including the following incentives:

- 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 customers' businesses;
- Incentives for homebuilders to construct homes that go beyond existing energy codes;
- Energy Management Programs where a specialist provides personalized energy-saving tips and rebate recommendations
- Energy saving kits provided to fifth-grade and high school students along with an inter-active instructional presentation on energy efficiency; and
- Incentives that specifically target energy efficiency improvements for lower-income and multifamily customers.

PNM promotes EE 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.

Once approved by the NMPRC, EE programs remain in effect until modified or canceled by the NMPRC. Descriptions of the specific programs offered appear in Appendix L.

3.2.2 Demand Response

Demand response programs reduce customer demand at times of peak load or during shortages of supply. PNM customers can opt to have portions of their load curtailed through the Power Saver and Peak Saver programs:

- The **Peak Saver** load management program is designed to help medium and large commercial customers with demand greater than 50 kW reduce the amount of energy they require during peak demand periods.
- The **Power Saver** load management program controls refrigerated air conditioning units in participating homes and small businesses during periods of peak demand. To facilitate load control, participants must have a device attached to the exterior of their air conditioning unit. This "paging" device is capable of receiving a radio signal that will activate a control sequence that cycles the unit's compressor for an interval of time (usually half the time as normal) to reduce peak demand in the summer. Alternatively, load curtailment is achieved via communication with a Wi-Fi-enabled thermostat.

These programs were approved by the NMPRC in Case No. 07-00053-UT and reauthorized in Case No. 16-00096-UT. PNM selected the demand response program contractors through a competitive bid process. Each program operates from June to September to help PNM manage peak summer loads. Participants' load may be curtailed up to 100 hours over the course of a year, with a maximum duration of four hours at any given time. Customers receive a minimum 10-minute notice for each curtailment event, though notice is typically provided farther in advance., These curtailment events cannot be called on weekend days or on the first weekday following a holiday weekend. Historically, the actual number of calls in a year has typically been between five and fifteen, though since 2019 the average has been five calls per year.

Historical Load Impacts

PNM relies upon the same measurement and verification process used for EE to evaluate the impacts of DR programs. In the most recent independent evaluation, Evergreen Economics notes the impact these programs had on PNM's peak demand:

> The evaluation team concludes that PNM's demand response (DR) programs, Power Saver and Peak Saver, were highly effective reducing peak demand during the summer of 2022 when PNM faced tight supply conditions. The [load management] programs achieved their intended objective of helping to fulfill PNM's reserve margin and responding quickly to operational needs. Both functions offset the need for construction or purchase of traditional peak capacity resources.

– Evergreen Economics, *Evaluation of the 2022 Public Service Company of New Mexico Energy Efficiency and Demand Response Programs*

The same independent review found that together, the Power Saver and Peak Saver programs together reduced peak demand by an average of 45 MW (see Figure 29). In light of both the specific challenges faced in summer 2022 with delays in the replacement resources for SJGS and the general growing concern surrounding resource adequacy, these verifiable peak demand reductions represent an important part of the portfolio.

Figure 29. PNM system load on June 10, 2022

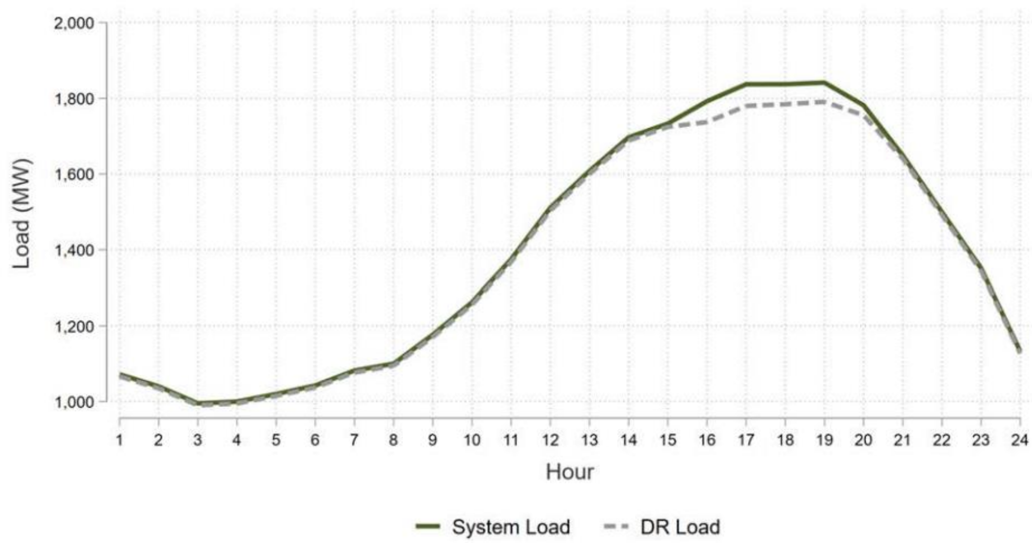


Figure reproduced from: Evergreen Economics, Evaluation of the 2022 Public Service Company of New Mexico Energy Efficiency and Demand Response Programs, available at: https://www.pnm.com/documents/28767612/39749933/PNM+2022+Independent+Evaluation+and+Verification+Report.pdf/88276ae0-f03e-32e8-b887-58176200090d?t=1683651341611

The Peak Saver and Power Saver programs are governed by 5-year contracts, ending in 2023, however PNM has proposed to extend operation of these two programs through 2026 in Case No. 23-00138-UT.

3.3 Trends in Usage and Customer Preferences

3.3.1 Customer Solar

PNM conducts regular customer surveys on a variety of topics to understand the priorities of consumers and how to best serve them. In one of the recent surveys of residential customers, PNM found that roughly one quarter of customers would find more options to purchase green power products "extremely useful," and over two thirds agreed that such offerings would be at least "moderately useful." The clear preference emerging among customers is for options to mitigate their environmental impact, which shapes the opportunities PNM provides.

Figure 30. Residential customer interest in green power purchase programs.

For customers that do have an interest in energy supply that has more renewable energy than PNM's generation portfolio, PNM offers net metering and voluntary programs, including PNM Sky Blue, PNM Solar Direct, and the newly established Community Solar pilot. These programs allow customers of all sizes to invest in their own on-site generation, or to procure renewable energy from utility scale resources. Because customers enrolled in these programs are voluntarily participating outside of PNM's standard service, the resources that serve the voluntary programs are not included in PNM's RPS accounting. This means that the actual fraction of renewable energy produced to serve PNM customers in a year will always be larger than the fraction reported for RPS compliance. Participation in these programs is expected to continue growing, leading to a percentage of renewable generation higher than what is required by the RPS.

Utility-led renewable energy programs provide an opportunity to meet customers' desire to tailor their energy use. Coordination between the IRP process and program design will remain important, particularly as PNM's portfolio shifts to renewable resources supplying the majority of customers' energy use. Understanding the system impacts from increased adoption of resources not counted in the RPS – privately owned resources and utility scale resources supplying voluntary programs – informs program and generation portfolio design.

PNM Sky Blue

Sky Blue is the voluntary green tariff program offered to PNM customers that want to upgrade more of their energy consumption to renewables. They can purchase blocks or a percentage of their overall consumption. The Sky Blue subscriptions are fulfilled using a mix of both wind and solar resources. Solar energy comes from 1.5 MW of solar from the Manzano Solar Energy Center (8 MW total) and wind is included based on subscription levels from the New Mexico Wind Energy

Center (NMWEC). Sky Blue is available to residential, commercial, and industrial customers. Subscription levels have fluctuated over time as customers may install their own behind-the-meter renewables or the awareness has declined. However, there is a growing interest in green tariffs from commercial customers to meet their green energy goals. This is helping to drive increased participation in the program overall, since 2021. As of October 2023, there are nearly 3,200 customers subscribed to Sky Blue.

PNM Solar Direct

PNM has also been working collaboratively with larger customers to provide increased choice in energy supply. Under a program approved by the NMPRC in 2020, customers with loads larger than 2.5 MW are eligible to subscribe to a portion of the output of the 50 MW Jicarilla 2 solar plant in Rio Arriba County. This program allows large customers the option to meet their sustainability goals through a fifteen-year commitment to purchase output from this facility. Jicarilla 2 is fully subscribed by nine large and governmental customers. The site was fully commissioned in April 2022 and customers receive a bill credit for their subscription each month.

Community Solar

The Community Solar Act, enacted by New Mexico's legislature in April 2021, requires PNM to interconnect 125 MW of small solar facilities and sell energy to targeted communities in support of the carbon-free goal. The community solar projects are selected by a third-party administrator based on viability and benefits to the community.

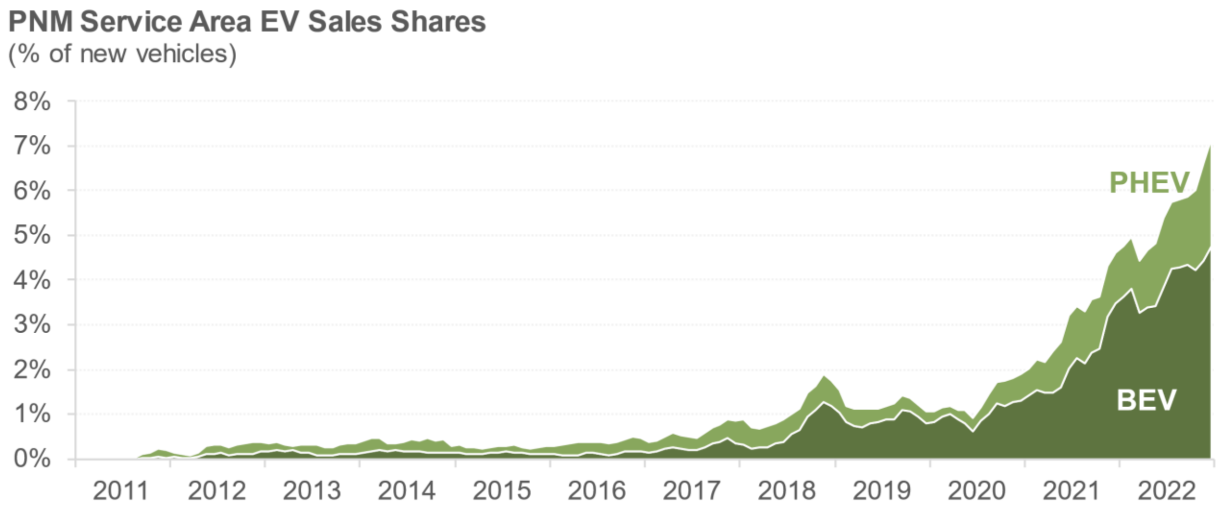
Customers who live in these communities benefit from a credit on their electric bill. The credit compensates customers for the energy produced by the Community Solar project, which reduces investments needed to make in other resources to produce this energy. Additionally, at least 30% of community solar will be sited in low-income communities. Approximately 50,000 customers may opt to participate during the pilot period, which continues until November 2024 when it will be superseded by a statewide program.

3.3.2 Electrification

In the past several years, PNM has observed a rapid acceleration in interest in electric vehicles. Figure 31 shows this recent rapid increase: for most of the past decade, the share of new vehicles that were fully or partially electric was less than 1%, but in the past few years that share grown significantly. At the end of 2022, nearly 7% of new vehicles sold in PNM's service territory were either battery electric vehicles (BEVs) or plug-in hybrid electric vehicles (PHEVs).

As the number of electric vehicles on the road grows, their impacts on the grid will continue to increase. The IRP incorporates a forward-looking projection of electric vehicle adoption into the demand forecast (discussed in Section 3.4), but PNM also recognizes the importance of being a proactive partner to customers as their preferences change. To that effect, PNM filed its Transportation Electrification Plan, which was approved by the NMPRC in November 2021 (Case No. 20-00237-UT). The plan provides incentives for EV chargers and electric transit, along with new rate plans and upgrades to the distribution system to support EVs. Additionally, 25% of the funding is reserved for low-income communities.

Figure 31. Sales share of electric vehicles in PNM's service territory



PNM expects its plan will provide both financial and environmental benefits for customers. EV adoption can enable customers to manage electric loads by choosing when they charge EVs. By charging during off-peak times, customers can lower electric rates by shifting load away from the hours of highest demand in a manner that provides benefits to all PNM customers. Customers will also benefit from reduced spending and air pollution by displacing gasoline with EVs powered by an increasingly cleaner grid.

In the future, New Mexico's continued pursuit of economy-wide decarbonization will likely drive additional electrification – not only of transportation, but of buildings as well. While only 20% of residential customers report heating their homes with electricity today, proliferation of heat pumps is expected to make electricity the primary heating fuel in the state. The same is true for water heating, where 13% of customers report electricity as their energy choice today.

The load growth from electrification presents an opportunity. With proper planning, significant segments of these new loads can be shaped to some extent to serve as a peak-reducing resource using a combination of rate signals and automatic controls. On the customer side, this management and the grid modernization technologies that enable it will improve the ability to communicate with customers and will lead customers to better engage with and understand their energy usage. On the system side, this management will lead to a more reliable and less costly system.

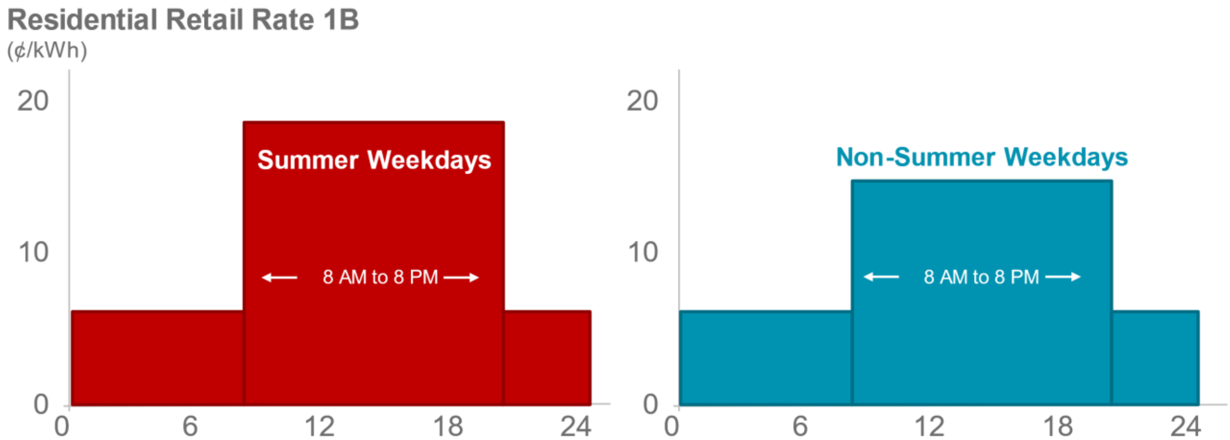
While PNM is beginning to incorporate electrification-driven increases in load in long-term planning, its forecasts under the Current Trends and Policy future do not include significant impacts from electrification within the timeframe of the planning period of this IRP. However, considering the continued push at a national level on economy-wide decarbonization, the increased incentives provided by the IRA, as well as requests from stakeholders, PNM analyzed a sensitivity with high electrification to help better identify the implications and potential actions needed for accelerated electrification.

3.3.3 Time-of-Use Rates

PNM offers time-of-use (TOU) rates for nearly all rate classes, including Residential, Small Power, General Power, and Large Power. These rates encourage customers to avoid usage during the time when the carbon emissions and cost to serve are 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 32 shows the current TOU rate offered to the residential class, as well as a proposed future TOU rate for the residential class. The illustrative future rate is not meant to be regarded as a rate proposal, but merely an illustration of the likely evolution of TOU periods to match periods when energy prices are expected to be highest. With large amounts of solar generation, midday prices will be suppressed, and the current TOU period will not be appropriate. Instead, TOU peaks will be designed to align with the heating and cooling demands that arise during shoulder periods of the day when solar generation is low. An additional rate tier was proposed in the Transportation Electrification Plan for EV owners to encourage vehicle charging overnight when demand is otherwise low. Though not shown, PNM proposed in the Transportation Electrification Program a new TOU rate for separately metered commercial EV charging stations to encourage EV charging from workplaces during the solar peak and at night. The alignment of TOU periods with evolving hourly variation in cost of service will ensure that customer load flexibility is used to keep rates low for future resource plans.

Figure 32. Current TOU offering (1B) for Residential customers



As the portfolio shifts to include more capital-intensive intermittent resources and fewer on-demand resources with high variable cost, PNM expects to be long on energy but short on capacity. This anticipated need for capacity results in the value of conservation decreasing and the value of temporal alignment of load with generation increasing. This shifting value means that moving more load onto Time-of-Use (TOU) rates is a critical part of the vision for future rate design.

Historically, all but the most basic TOU rates were considered too complex for residential customers, but this thinking has changed. Customer sophistication has increased, more and better tools facilitate communication between PNM and customers, "smart" appliances allow for load shifting with minimal customer intervention, and electrification of more end uses creates an abundance of flexible load. Accordingly, default residential rates with TOU components have been proposed, adopted, and implemented in nearby jurisdictions.

In the Transportation Electrification Program, PNM proposed a set of limited-enrollment TOU rates to improve alignment between the wholesale and retail cost of electricity at different times of day. These rates include a residential TOU EV rate and a Commercial EV Charging TOU rate.

The Residential TOU EV rate structure has a super off-peak period that incentivizes overnight EV charging, as requested anecdotally by EV owners in PNM's service territory.

Stakeholder Input: Future Impacts of Dynamic Rates

During the facilitated stakeholder meetings, Stakeholders encouraged PNM to build on the success of its TOU pilot and move toward enrolling more customers in time-varied rates. To better understand the impact and value that TOU rates could have on long term plans, PNM includes a modeling sensitivity in which residential load is shifted in response to an example TOU rate. See Section 3.4.3 for additional details.

In an upcoming rate case, PNM plans to propose further expansion of TOU rates, including a Residential TOU rate and a Small Power TOU rate. Moving from the current rates to default service TOU pricing will not happen overnight. Currently PNM lacks the Advanced Metering Infrastructure (AMI) required to collect and manage TOU data from all residential customers. However, PNM recognizes that New Mexico's grid modernization legislation, House Bill 233, creates a pathway for AMI investment.

3.3.4 Advanced Demand-Side Programs

The transition to a supply portfolio that includes high amounts of renewable energy results in a decrease of supply-side flexibility to align generation with load. This can be countered with an increase in demand-side flexibility to align load with generation. PNM expects opportunities for demand-side flexibility to multiply in the coming years through proliferation of smart appliances, advanced metering, and other grid modernization technologies.

In time, PNM hopes to install AMI throughout its service territory. PNM has already discussed how AMI deployment would allow for TOU rate designs which encourage customers to shift their flexible loads to off-peak hours. TOU designs can change over time in sophistication and in the peak period definition to ensure that load shifting avoids capacity and reduces the cost to serve all customers. As EV adoption increases and more smart appliances appear in homes and businesses, customers will have increased flexible load with which to take advantage of such rates.

Outside of rate signals, load flexibility can be achieved through grid modernization investments such as Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS). One function of these systems is to utilize the enhanced visibility provided by AMI for two-way communication between the grid and customer devices like EVs, heat pumps, BTM solar, BTM energy storage, and other smart appliances. Programs leveraging this functionality are the natural successors to Peak Saver and Power Saver, but a modernized grid allows this communication to be continuous and dynamic instead of on a call basis.

Widespread deployment of sophisticated TOU rates and load management programs is a long-term process. Technologies in the space continue to evolve and many system impacts remain too uncertain to warrant inclusion in the IRP modeling. The flexible load considerations in this IRP are the traditional demand response programs described in Section 6.1 and the TOU rate sensitivity described in Section 5.1.3.

Efficient alignment of load to generation becomes increasingly important as PNM moves towards the carbon emissions-free goal. In the coming years, PNM plans to pursue technologies that enable flexible loads in the distribution planning process to ensure optimal benefit to customers and to the resource planning process; however, advanced metering infrastructure is a precursor to achieving these objectives.

3.4 Future Demand Forecast

Load forecasting is a fundamental component of resource planning. Variable loads will impact the timing and amount of generation additions and retirements, as well as the transmission and distribution infrastructure needed to deliver energy. Further, the load forecast is arguably the most critical piece in scenario planning, which helps to explore possible future conditions.

The load forecast and associated sensitivities are essential inputs to the IRP, especially in times of more volatile loads. Over the past half century, PNM's electric loads have undergone several dramatic shifts that directly shaped the electric system as it exists today. Loads grew rapidly and steadily post-World War II as Sunbelt regions like New Mexico experienced major growth. In addition, New Mexico experienced a huge investment in defense infrastructure with national laboratories and military bases. This unprecedented increase in the need for electricity brought forth the construction of large baseload plants like Four Corners (FCPP), San Juan (SJGS) and Palo Verde (PVNGS). Later, PNM was affected by the rise and fall of uranium mining in New Mexico. The industry was the largest customer group in terms of energy, either directly buying energy from PNM, or through supply contracts with electric cooperatives serving the mines. Gearing up to serve that load and then dealing with its collapse in the 1980s following the events of Three-Mile Island had huge implications for PNM's resource planning.

Presently, PNM faces the potential for another period of transformative changes in electricity demand. Recent load increases, particularly those driven by large industrial loads, are notable examples. Moreover, policy directions for greenhouse gas emissions reduction increasingly emphasize the electrification of the economy; therefore, PNM anticipates further impact to utility service demand as transportation, space heating, and other energy sectors potentially transition to electric solutions.

3.4.1 Methodology

To create the load forecasts, PNM develops rate-level projections for residential, small power, and general power classes, including usage per customer and the number of customers in each class. For large power customers, individual forecasts are prepared due to their significant loads. These forecasts rely on historical load data, incorporating temperature and solar profiles from multiple locations within the service territory. PNM also adjusts load data to exclude the impact of behind-the-meter generation and normalize it with historical weather metrics.

Statistically-adjusted, end-use models are used to predict future loads, accounting for factors such as economic growth, appliance saturation, energy efficiency, and the adoption of new technologies like electric vehicles, BTM solar, and heat pumps. The load forecast also reflects the cumulative effect of prior years' energy efficiency programs. As PNM addresses the effects of climate change, climate-adjusted weather years are integrated into the load forecast to consider extreme temperature impacts on heating and cooling loads, which significantly contribute to customers' total demand. Finally, customer-level load is grossed up to account for losses in the distribution and transmission systems between the point of generation and the point of delivery.

This analysis allows PNM to evaluate whether a resource is located on the supply or demand side of the customer meter and to assess its value to the system.

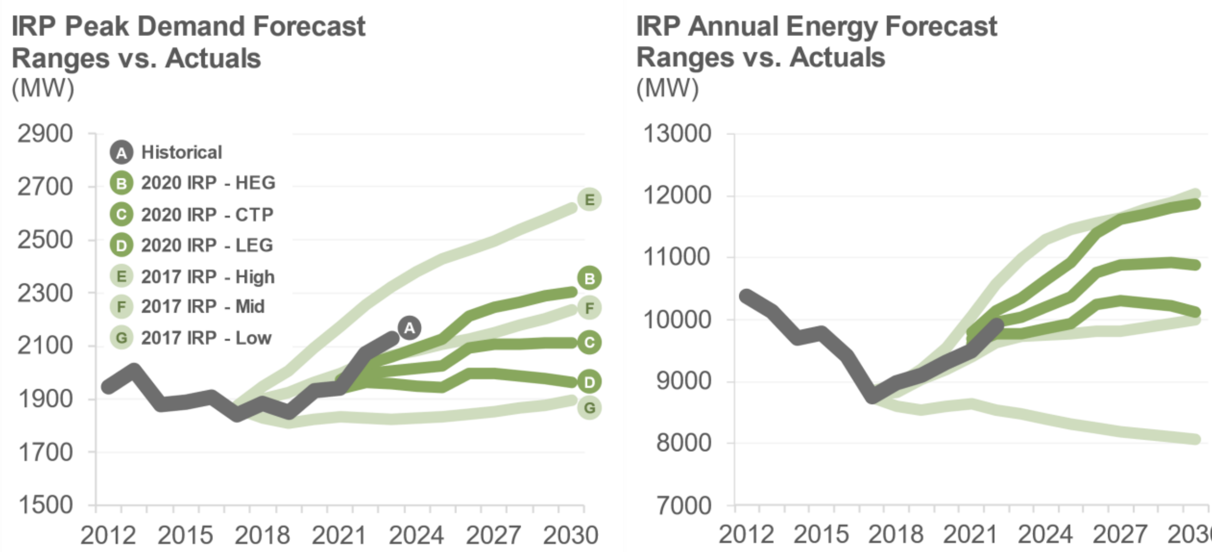
Two adjustments are applied to the initial results of these forecasts:

1. Loads in several cases are adjusted upward to reflect a plausible higher rate of growth of large economic development loads. This ensures that a broad range of load trajectories are studied in the IRP; and
2. In all cases, the impacts of future energy efficiency measures assumed to be embedded in the load forecast are removed to allow for energy efficiency to be treated as a resource. The methods used to characterize those opportunities, including both measures to meet the requirements of the EUEA and additional programs, are discussed in Section 6.1.

Historical Forecast Accuracy

The process and methodology used to forecast future demand for the purposes of long-term planning has generally produced reasonable results when compared against actual historical demand. Figure 33 compares PNM's actual historical peak demand against the range of forecasts developed in the 2017 and 2020 IRPs. In the overlapping periods, actuals have tracked reasonably closely to the "base case" forecasts used in ("Mid" in 2017 and "Current Trends and Policy" in 2020). Most recently, however, increases in peak demand driven by economic development in the region have caused actual peak demand to exceed those forecasts, indicating the importance of considering a range of potential future outcomes in planning. These types of deviations are accounted for by the range of different load forecasts considered.

Figure 33. Comparison of load forecasts developed in prior IRPs against historical peak demand



HEG = High Economic Growth, CTP = Current Trends & Policy; LEG = Low Economic Growth; 2020 IRP forecasts include peak load impacts of energy efficiency measures selected in Technology Neutral scenario

Table 13 provides additional detail comparing the accuracy of peak demand forecasts developed in both the 2017 and 2020 IRPs against actual results during overlapping periods. In most overlapping years, the forecasts used within the IRP are within 5% of the actual peak demand. As an exception, the actual peak demand in 2023 was roughly 6% higher than the Current Trends & Policy demand forecast in the 2020 IRP. PNM's peak demand in 2023 of 2,131 MW set a record for the system, driven by weather conditions more severe than typical summer conditions in New Mexico. Considering that year-to-year weather variability can cause variations in peak demand of this size, this recent variance is natural in the process of forecasting peak demand.

Table 13. Comparison of peak demand forecast actuals against IRP load forecasts

	2018	2019	2020	2021	2022	2023
Actual Peak Demand (MW)	1,885	1,853	1,931	1,940	2,072	2,131
2017 IRP Mid Forecast (MW)	1,900	1,926	1,961	1,999	2,041	2,064
2017 IRP Forecast Variance (%)	0.8%	3.9%	1.6%	3.0%	-1.5%	-3.1%
2020 IRP CTP Forecast (MW)	*n/a*	*n/a*	*n/a*	1,956	1,996	2,006
2020 IRP Forecast Variance (%)	*n/a*	*n/a*	*n/a*	0.8%	-3.7%	-5.8%

3.4.2 Forecast Summary

Using the methodology described above, a wide range of load forecasts are developed for the IRP. Each forecast represents a specific set of assumptions regarding demographic growth, economic development, BTM solar adoption, EV adoption, building electrification, TOU pricing, and weather conditions.

The first four items listed in the table below correspond to the primary "futures" investigated through the IRP. Each of these scenarios reflects a distinct vision of the future:

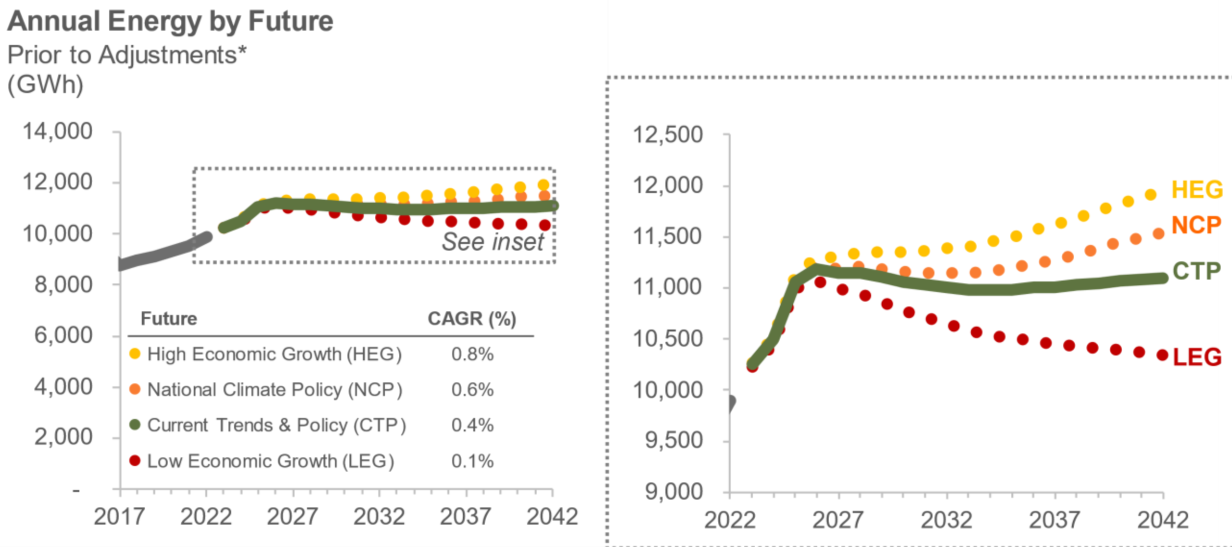
- **"Current Trends & Policy"** reflects the best estimates of the future state of the world based on the knowledge at the time of the IRP's development. In this case, local economic growth and accelerating adoption of electric vehicles are partially offset by increasing customer adoption of solar, leading to relatively modest growth rates (0.4% per year for energy; 0.9% per year for peak demand).
- **"High Economic Growth"** reflects a future of rapid economic expansion in New Mexico. In addition to driving an increase in the growth of electric demands, this future incorporates greater levels of customer adoption of solar resources and electric vehicles.
- **"Low Economic Growth"** assumes a slowdown of growth in New Mexico – an environment that would also plausibly lead to reductions in the rates of customer adoption of solar and electric vehicles.
- **"National Climate Policy"** assumes that, in support of policy-driven efforts to reduce greenhouse gas emissions, customers accelerate adoption of solar, electric vehicles, and building electrification technologies, driving an increase in electric load.

Table 14. Summary of assumptions used in various load forecast scenarios

Future	Economic Forecast	Economic Dev Loads	BTM Solar	EV Adoption	Building Elec	TOU Pricing Impacts	Weather
Current Trends & Policy	Mid	Limited	Mid	Mid	Mid	No	Normal
High Economic Growth	**High**	**Stable**	Mid	Mid	Mid	No	Normal
Low Economic Growth	**Low**	Limited	**Low**	**Low**	Mid	No	Normal
National Carbon Policy	Mid	**Stable**	**High**	**High**	**High**	No	Normal
Sensitivity	**Economic Forecast**	**Economic Dev Loads**	**BTM Solar**	**EV Adoption**	**Building Elec**	**TOU Pricing Impacts**	**Weather**
Stable Economic Development	Mid	**Stable**	Mid	Mid	Mid	No	Normal
High BTM Solar	Mid	Limited	**High**	Mid	Mid	No	Normal
Low BTM Solar	Mid	Limited	**Low**	Mid	Mid	No	Normal
Zero Incremental BTM Solar	Mid	Limited	**Zero Inc**	Mid	Mid	No	Normal
Zero BTM Solar	Mid	Limited	**Zero**	Mid	Mid	No	Normal
High EV Adoption	Mid	Limited	Mid	**High**	Mid	No	Normal
Low EV Adoption	Mid	Limited	Mid	**Low**	Mid	No	Normal
High Building Electrification	Mid	Limited	Mid	Mid	**High**	No	Normal
TOU Pricing	Mid	Limited	Mid	Mid	Mid	**Yes**	Normal
Extreme Weather	Mid	Limited	Mid	Mid	Mid	No	**Extreme**

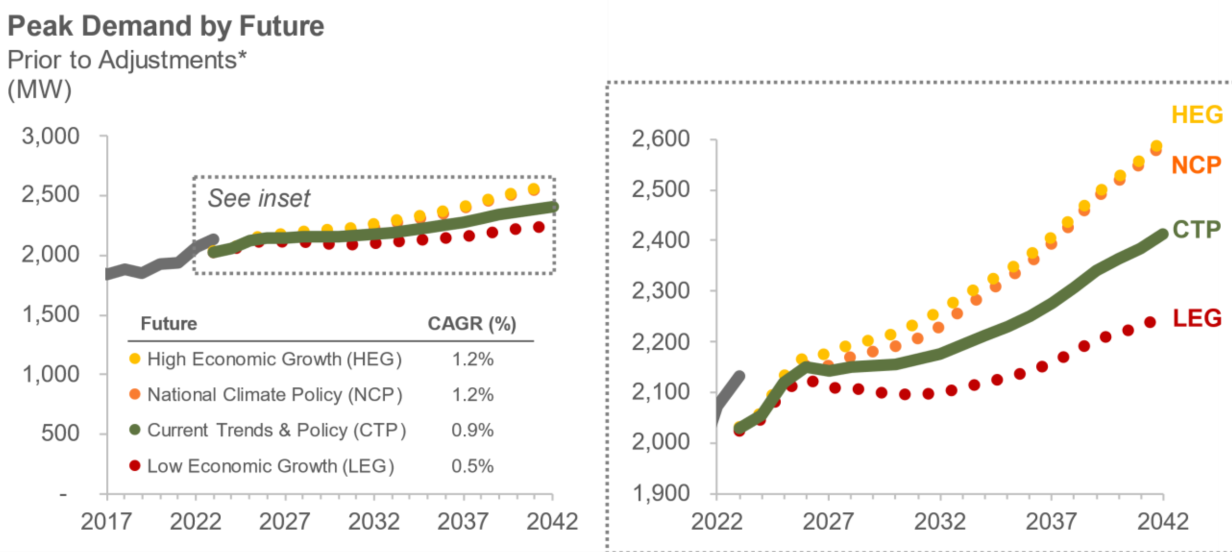
The annual energy and peak demand for each of the four futures are summarized in Figure 34 and Figure 35, respectively. Additional details for each of the demand forecasts are provided in Appendix C.

Figure 34. Forecasts of annual energy demand under different futures



* Two additional adjustments are applied to load forecasts: (1) all forecasts are adjusted to remove load impacts of energy efficiency, and (2) select forecasts are adjusted to include additional economic development loads. These adjustments are described below

Figure 35. Forecasts of peak demand under different futures



* Two additional adjustments are applied to load forecasts: (1) all forecasts are adjusted to remove load impacts of energy efficiency, and (2) select forecasts are adjusted to include additional economic development loads. These adjustments are described below

The remaining items listed in Table 14 represent a range of sensitivities upon the Current Trends & Policy future, in which one input parameter is varied to examine its impact. While a large number of sensitivities were created in the load forecast process, a select few were carried forward for subsequent analysis in the IRP. Selection of specific sensitivities to study in the IRP was determined by multiple factors:

1) Stakeholder input: in the facilitated stakeholder process, many stakeholders offered comments that ultimately impacted the prioritization of certain sensitivities.

2) Breadth of outcomes: PNM's load is inherently uncertain, and effective planning requires consideration of a broad range of potential outcomes; certain sensitivities were included to ensure this range of conditions studied was sufficiently broad.
3) Understanding impacts: the analysis of certain sensitivities can provide important information to PNM, the NMPRC, and stakeholders that may help inform future decisions.

Forecast Adjustment for Stable Economic Development Loads

PNM currently provides service to one large data center load but has recently received inquiries regarding the potential to supply electricity to new large economic development projects. These loads are associated with industrial and data center customers and tend to have very high load factors (i.e. relatively high usage at all times of day and year). These types of projects could result in substantial increases to future loads and associated resource needs. Whether these projects come to fruition is also a significant source of uncertainty.

Most load forecast scenarios developed for the IRP reflect a **"Limited"** trajectory of economic development loads, which is based on the probability-weighted sum of specific economic development projects identified by PNM. In order to stress-test the portfolio analysis in the IRP and ensure that the results are robust even under the prospect of significantly higher growth rates, the load forecasts in select futures are adjusted to reflect a **"Stable"** trajectory, which includes a much higher expectation of economic development projects materializing over the forecast period. This alternative trajectory results in an increased peak demand of approximately 250 MW by 2030 and nearly 1,100 MW by the end of the horizon.

This adjustment is applied to two futures: High Economic Growth and National Climate Policy. In the former, the use of the Stable ED trajectory reflects the possibility that continued economic growth in the region could continue to attract new large customers; in the latter, the use of the Stable ED trajectory reflects the possibility that industrial policies primarily oriented around climate change that encourage domestic manufacturing and other industry could also lead to substantial growth of large customers in the region. The impacts of the adjustment to include the Stable ED trajectory is shown in Table 15.

Table 15. Impact of Stable Economic Development adjustment on HEG and NCP futures

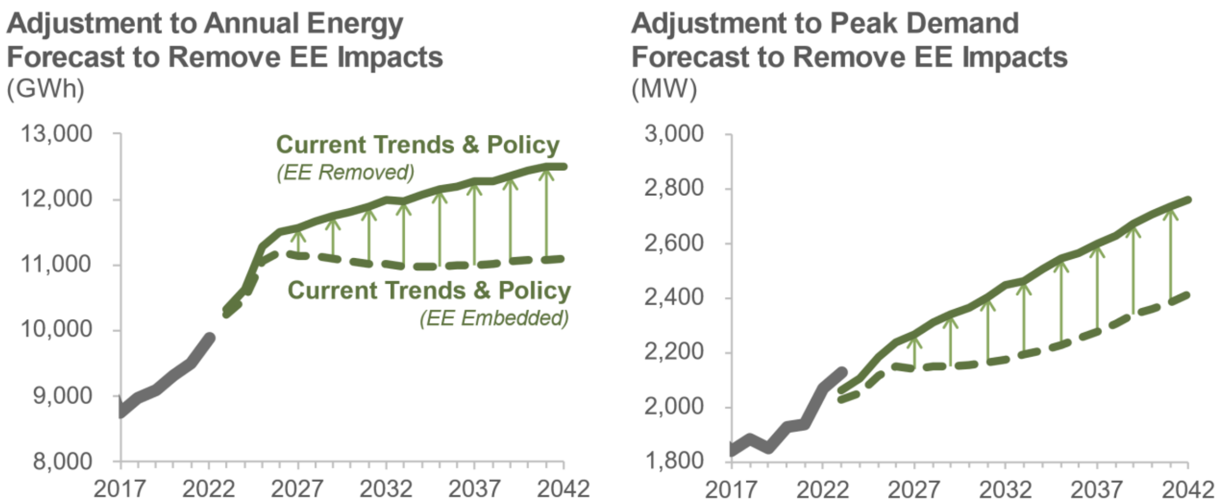
	Annual Energy (GWh)			Peak Demand (MW)		
Metric	**2023**	**2042**	**CAGR %**	**2023**	**2042**	**CAGR %**
High Economic Growth (before ED adjustment)	10,264	11,953	0.8%	2,031	2,597	1.2%
High Economic Growth (with ED adjustment)	10,264	20,738	3.6%	2,031	3,686	3.0%
National Climate Policy (before ED adjustment)	10,249	11,542	0.6%	2,028	2,591	1.2%
National Climate Policy (with ED adjustment)	10,249	20,327	3.5%	2,028	3,679	3.0%

Forecast Adjustment for Embedded Energy Efficiency

One of the enhancements introduced in the 2020 IRP was the explicit treatment of energy efficiency programs as a resource option that could compete against supply-side options in the optimization of the portfolio. Rather than planning a supply-side portfolio to meet demand reflecting a static forecast of future efficiency, this enhancement allows the IRP to consider the role of efficiency more dynamically in the construction of the portfolio.

The 2023 IRP continues to use this approach to incorporate efficiency into the planning process. Treating efficiency as a resource option requires the load forecast to be adjusted upward, reflecting the embedded impact of future energy efficiency to avoid double-counting. The result of this adjustment is a higher load forecast that is used in the analysis. This adjustment to both annual energy and peak demand is illustrated in Figure 36 for the Current Trends & Policy future; the same adjustment is applied to all other futures and sensitivities analyzed.

Figure 36. Illustration of load forecast adjustment to remove load impacts of efficiency to allow treatment of efficiency as a resource in IRP analysis



Commensurately, "bundles" of energy efficiency measures are characterized by their load impacts and costs and are included as resource options as discussed in Section 6.1.1. To the extent the bundles are selected in the portfolio, their inclusion would represent a load reduction relative to the "EE Removed" load forecast.

3.4.3 Key Assumptions in Load Forecast

The results described above reflect a buildup of sectoral load shapes and a number of key load modifiers. These drivers are discussed in further detail in this section.

Economic and Demographic Changes

Economic and demographic factors are a key driver of PNM's future load growth. The demand forecasts are based on projections of (1) population growth in the service territory, (2) increases in the number of non-manufacturing jobs, and (3) real per capita income growth. Projections for each of these parameters, provided by Woods & Poole at the state and county level, are used as inputs to model future load based on historically observed relationships. The assumptions for each of these parameters are shown in Table 16. When compared against the 2020 IRP, the 2023 IRP reflects slightly lower levels of population growth and non-manufacturing job growth and slightly higher growth of real per capita income in the region.

Table 16. Economic & demographic assumptions in the 2023 IRP

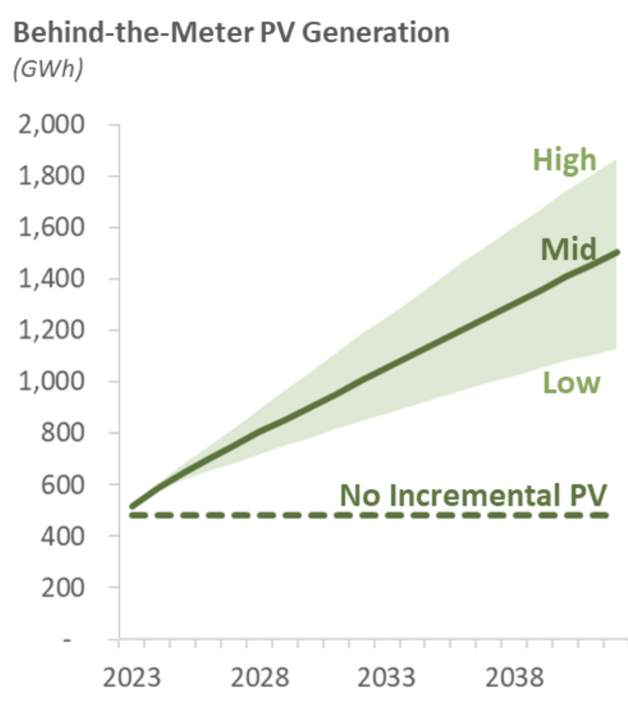
Input Data	Low	Mid	High
Population Growth *(# per year)*	**4,400** *(4,800)*	**9,400** *(9,800)*	**14,400** *(15,800)*
Non-Manufacturing Employment Gains *(# per year)*	**2,800** *(3,500)*	**5,800** *(6,500)*	**9,300** *(10,000)*
Real Per Capita Income Growth *(% per year)*	**1.1%** *(0.6%)*	**1.5%** *(1.0%)*	**1.8%** *(1.3%)*

Values in parentheses reflect assumptions used in the 2020 IRP load forecast

Behind-the-Meter PV

PNM's IRP analysis considers a range of future BTM solar adoption, reflecting customers' increasing interest in renewable energy. Projections reflect an acceleration of BTM solar adoption in the past few years, even during the COVID-19 pandemic. As such, the BTM solar capacity modeled in the 'Low' case exceeds the Mid used in the 2020 IRP. The current forecast is shown in Figure 37.

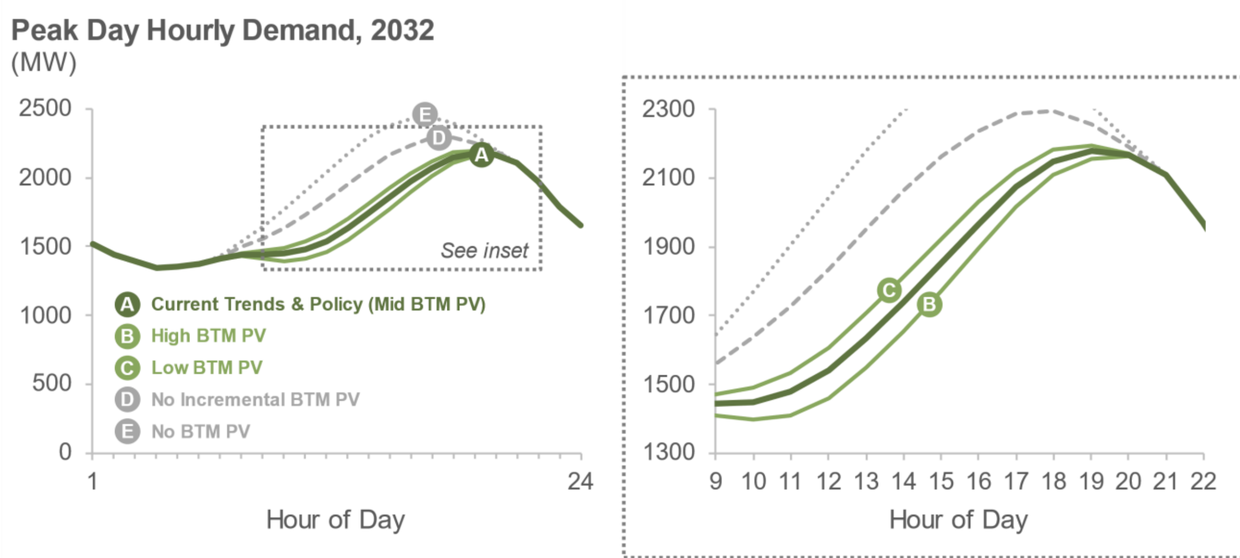
Figure 37. Range of BTM solar generation studied in IRP



In addition to the range of scenarios reflecting continued growth of BTM solar, the load forecast development process also includes a scenario in which no incremental BTM solar is added beyond 2023, as well as a counterfactual scenario in which no BTM solar exists on the system. These scenarios are not included as plausible outcomes but instead provide useful information on the value that existing and future BTM solar resources provide to the system.

Sensitivities on BTM solar adoption reflect a plausible range of outcomes given increasing consumer preferences for customer-owned solar PV. These customer-sited solar systems are usually installed on rooftops but may have ground-mounted applications for some larger customer installations. BTM solar sensitivities range from eliminating BTM solar entirely, to a "High" forecast in which BTM solar production peaks at 1,141 MW in 2042. It is important to note that while BTM solar additions initially decrease peak load, this impact is less significant at any levels of adoption above that of the "Low" BTM solar forecast. This declining impact is expected because BTM solar shifts the peak to later hours, from 5-6 pm today to 7-8 pm by 2042, when there is little-to-no insolation, aligning with the declining impact of supply-side solar described in Section 6.2.

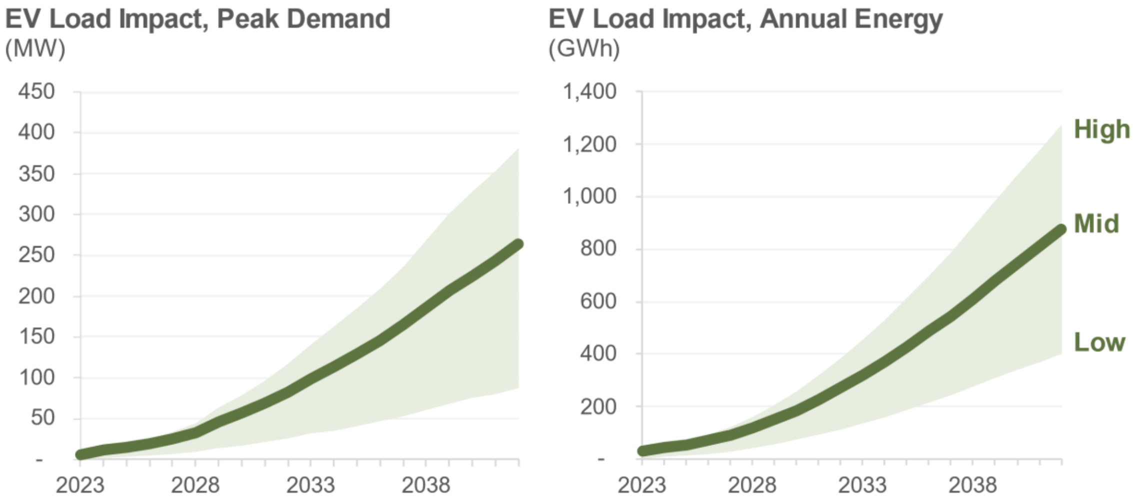
Figure 38. Impacts of BTM solar sensitivities on load shape and peak demand



Transportation Electrification

Currently, demand from electric vehicles represents a small share of annual retail loads (less than 1%). As of 2021, the number of electric vehicles in PNM's service territory is estimated at approximately 3,800. Looking forward, PNM expects this segment of loads to grow significantly with increasing adoption of new electric vehicles. The "Mid" electric vehicle adoption scenario assumes that by 2042, this figure will increase to 209,000 EVs. This is approximately 50% higher than forecast in the 2020 IRP, reflecting the rapidly growing sales of EVs in New Mexico and the U.S. "Low" and "High" sensitivities capture a range of adoption of 150,000 to 304,000 vehicles by 2042. The implied increases in load in these scenarios are shown in Figure 39. With the projected acceleration in EV adoption over the forecast period, transportation electrification loads are expected to become an increasingly significant component of PNM's future loads.

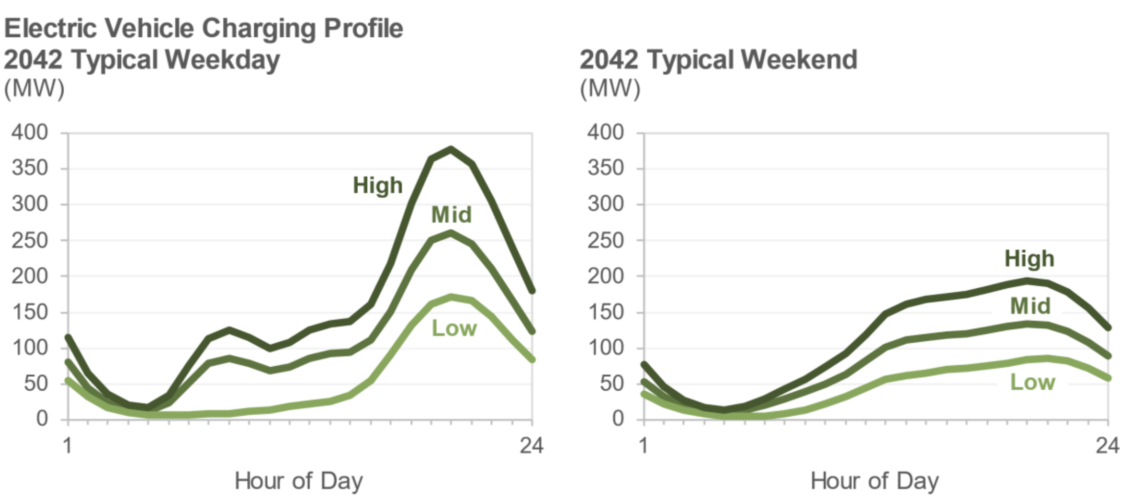
Figure 39. Range of electric vehicle loads considered in load forecast development



While the projections developed for the IRP are based on plausible ranges of market growth, state and national policy may also play a role in the rate of electric vehicle adoption. In studies of economy-wide decarbonization, transportation electrification has commonly been recognized as a significant potential source of carbon reductions. The transportation electrification program and the IRA both provide financial incentives for EV deployment that may impact the forecast. PNM will continue to monitor this landscape as it evolves and ensure the planning efforts remain aligned with market trends and the state's policy priorities.

In addition to the rate of EV adoption, PNM also considers when drivers choose to charge their vehicles, as the timing can significantly impact peak load. Using shapes developed by Idaho National Labs and NREL, PNM models three profiles: an unmanaged profile where EVs begin charging immediately after they the owners are finished driving, and two managed profiles where charging can start or end at a specified time to reduce the impact on peak load. Typical daily profiles included in the IRP are shown in Figure 40.

Figure 40. Typical weekday and weekend profiles for electric vehicle charging



Building Electrification

Another potential source of future load growth is the electrification of building end uses. Like transportation electrification, building electrification has been identified in many studies as an effective strategy to support economy-wide carbon reductions. The impacts of the Inflation Reduction Act's tax credits for building electrification may lead to higher levels of adoption than the mid-level forecast.

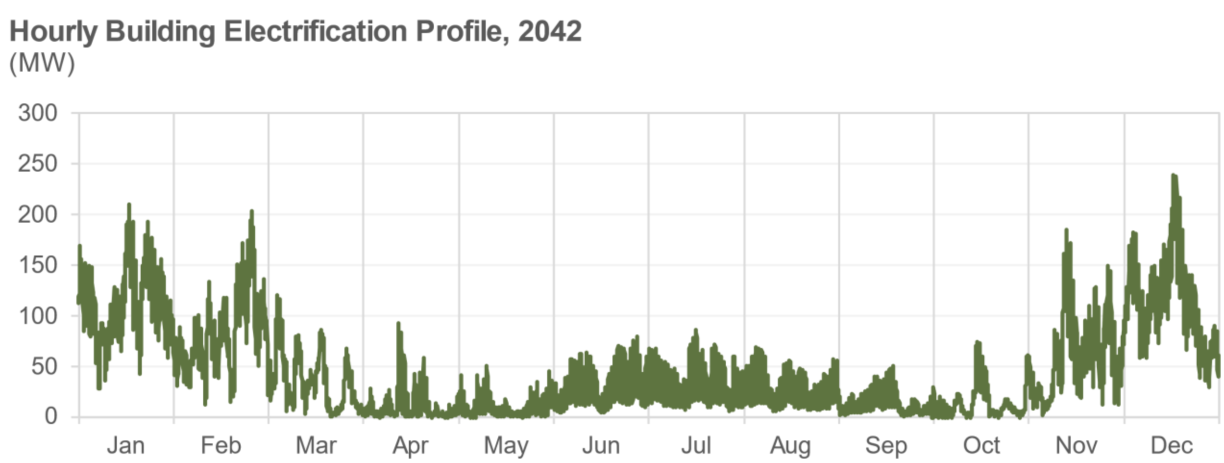
While most of the load forecast scenarios studied in this IRP do not incorporate future building electrification, it is incorporated into a select set of futures and sensitivities. In these cases, a "High" building electrification forecast assumes that beginning in 2025, new homes rely on electric space heating instead of natural gas and oil and that 7,000 existing homes convert to electric heat pumps each year. In combination, these measures increase the share of buildings with electric heat to 45% by 2042, increasing PNM's annual electric load by approximately 400 GWh (roughly 4% of today's energy demand).

Stakeholder Input: Incorporating Building Electrification

In response to stakeholder requests and recent policy developments, PNM developed a "High Building Electrification" forecast in which the switch from gas and oil heating to electric heat pumps in existing homes accelerates. This sensitivity was included in PNM's Phase 3 scenario analysis and in one specific stakeholder-requested scenario.

Electrification of space heating and water heating end uses in buildings would also alter the shape of PNM's demand throughout the year. Figure 41 shows hourly load shape for incremental loads introduced in the High Building Electrification sensitivity, illustrating how the load impact associated with these measures is expected to be larger in the winter (predominantly due to space heating). At this level of building electrification, PNM would remain a summer peaking system – the winter peak in 2042 remains approximately 400 MW lower than the summer peak – but the incremental loads in the winter do have implications for PNM's resource adequacy needs in a carbon-free portfolio when reliability risks may surface in the winter.

Figure 41. Hourly shape of incremental building electrification loads modeled in High Building Electrification sensitivity

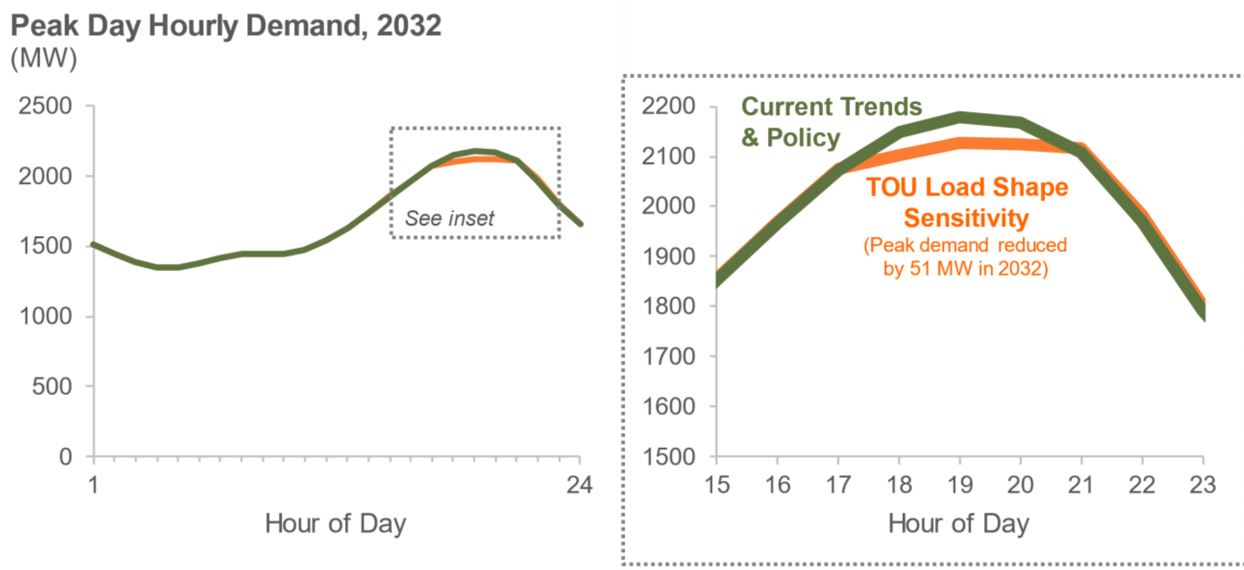


Time of Use Pricing

As discussed in Section 3.3.2, PNM is currently considering expansion of Time-of-Use (TOU) pricing to new customer classes in the future. By better aligning customers' retail rates with PNM's own underlying cost of producing electricity, TOU pricing can incentivize reductions in consumption during the peak period, reducing the need for investments to maintain resource adequacy. To characterize the potential benefits of the implementation of TOU pricing, the IRP includes a sensitivity that captures the expected effect of TOU pricing on load shape.

Sensitivity analysis is based on a TOU pricing scheme in which the highest cost hours occur from 5-8 am and 5-8 pm, which PNM expects to align with periods of most constrained supply in the near term. Additionally, PNM considers an EV rate where electricity would be cheapest from 10 pm to 5 am. These rates would begin as pilots in 2025 before becoming full programs by 2030; forecasts suggest that these programs could reduce the peak by 6% and customers' annual energy consumption by 1%. The impact that this has on the peak day load shape is illustrated in Figure 42, but will vary by year due to growth and changes in the shape of retail load. By 2042, PNM estimates that TOU pricing could reduce peak demand by 74 MW.

Figure 42. Impacts of TOU pricing sensitivities on load shape and peak demand



In the long term, it may be prudent to further adjust TOU periods to maintain alignment with the underlying cost of supply as PNM integrates additional renewable and storage resources. For simplicity, the peak period is not adjusted during this analysis, but PNM recognizes that maximizing the value a TOU pricing program will require continuous reevaluation of how to structure the periods.

4 PNM's Existing System

Chapter Highlights

- PNM's existing generation portfolio currently includes a diverse mix of nuclear, coal, natural gas, solar, wind, and energy storage resources. This portfolio has evolved significantly in recent years due to significant additions of renewable and storage generations and the retirement of SJGS, previously the largest resource in the portfolio.
- Over the next eight years, several existing resources are expected to exit the portfolio: PNM will exit FCPP by no later than 2031; PNM's original Valencia PPA is currently set to expire, and the Reeves Generating Station will reach the end of its depreciable life. PNM anticipates its other existing resources will remain in the portfolio throughout most of the 20-year planning horizon.
- PNM's existing nuclear, wind, and solar plants – including its 288 MW ownership share of PVNGS – currently produce enough carbon-free energy to meet over half of PNM's retail electric demands. Many of these resources will remain in PNM's portfolio through 2040 and will continue to play an important role in enabling reliability during the transition to a carbon-free portfolio.
- The existing PNM transmission system allows for the delivery of existing resources to load centers. Today, many parts of the PNM transmission system are fully subscribed and experience constraints delivering power into the northern New Mexico load center and between the southern and northern New Mexico service territories. These constraints will shape where new generation can be integrated into the system and what types of new transmission may be needed. This will influence future RFPs as PNM plans to ensure RFPs are locationally optimized to use the existing transmission system as much as possible.

One of the first steps in developing the long-term plan is a comprehensive assessment of the characteristics and capabilities of existing resources. This chapter summarizes the characteristics of existing supply-side resources, as well as the transmission and distribution grid that transports energy from these resources to customers.

4.1 Generation Resources

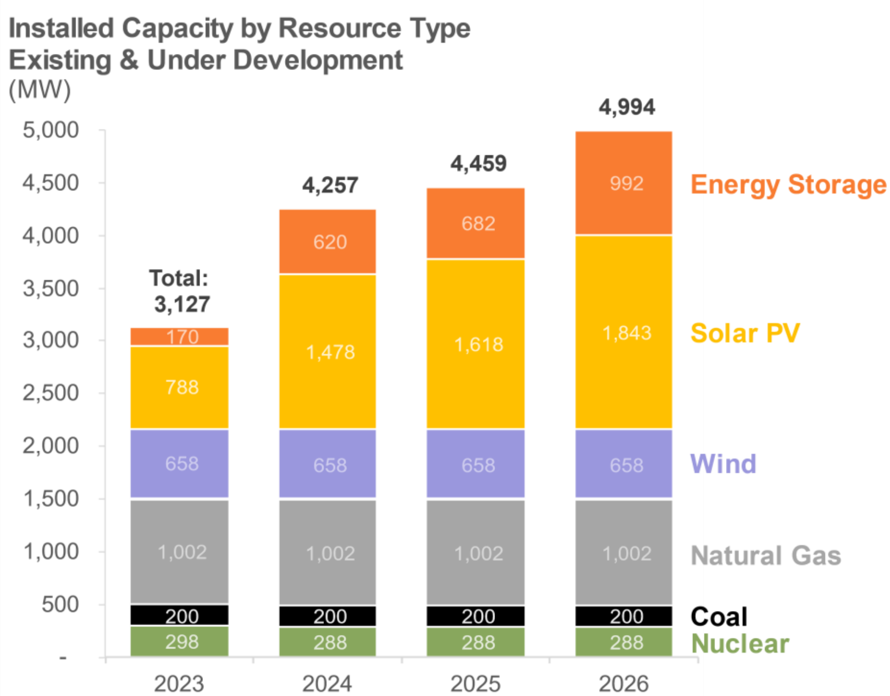
Today, the supply portfolio includes a mix of nuclear, coal, natural gas, solar, wind, energy storage, and demand-side resources. PNM has reshaped the portfolio significantly in the past decade with the retirement of the San Juan Generating Station and additions of significant carbon-free resources. With this shift, the carbon intensity of the generation portfolio has declined – from 1,355 lbs/MWh in 2015 to 903 lbs/MWh in 2022 – marking further progress in the plan to transition to a carbon-free portfolio. Most of the resources in the portfolio today will serve as the foundation for the remainder of this transition to support system reliability. Today, the supply-side generation portfolio includes:

- A 288 MW ownership share of the Palo Verde Nuclear Generating Station (PVNGS);
- A 200 MW ownership share of the Four Corners Power Plant, the last remaining coal-fired resource in the portfolio and one that is planned for exit no later than 2031;

- Over 1,000 MW of natural gas fired generation capacity across seven plants (six owned by PNM and one contracted through a PPA that expires in May 2028);
- Five power purchase agreements with wind generation facilities in eastern New Mexico, totaling over 600 MW of nameplate capacity;
- Over 1,800 MW of solar PV generation capacity, including many small (<10 MW) utility-owned projects and larger power purchase agreements both existing and under development.
- Energy storage agreements representing 1,000 MW of capacity, many of which are scheduled to come online over the next several years, and;
- The Dale Burgett facility, a 11 MW geothermal plant in southern New Mexico.

The composition of the current portfolio, including both resources operational today and under development, is shown in Figure 43. Additionally, the portfolio includes both energy efficiency and demand response resources, discussed in Section 3.2.

Figure 43. PNM's current generation portfolio, including existing resources and resources under development (nameplate capacity)



Note: PNM's existing portfolio also includes 11 MW of geothermal (included in totals)

While the figure above shows the installed nameplate capacity, PNM's progress to meet its carbon-free goals is largely dependent upon the energy mix, how much of customer's day-to-day needs are supplied by each of these resources throughout the year. Table 17 summarizes key statistics for the portfolio for the 2022 operating year, including annual net generation, greenhouse gas emissions, and water consumption from resources owned by and under contract to PNM.

Table 17. Key statistics for PNM's existing resource portfolio (based on 2022 historical operations)

Facility	Annual Net Generation (MWh)	Share of Annual Generation (%)	Total CO2 Emissions (short tons)	Carbon Intensity (lbs/MWh)	Total Water Use (000 gallons)	Water Use (gal/MWh)
Nuclear	3,257,339	28%	-	-	56,692	18
Coal	3,376,291	29%	4,116,060	2,440	2,034,235	603
Natural Gas	2,194,702	19%	1,161,471	1,084	402,614	184
Geothermal	47,073	0%	-	-	0	0
Wind	1,940,017	16%	-	-	0	0
Solar	948,100	8%	-	-	0	0
Total	**11,763,523**	**100%**	**5,277,531**	**903**	**2,493,541**	**212**

Table Notes

A. Includes 65 MW of merchant capacity at SJGS owned by PNM

As coal resources are replaced with renewables and storage, metrics related to environmental performance will improve. In 2022, SJGS and FCPP were responsible for over 80% of the carbon emissions from PNM's generation fleet; the retirement of SJGS in 2022 has already significantly reduced the carbon intensity of the generation portfolio, and PNM's exit from FCPP by 2031 will similarly reduce carbon intensity and water usage. At the same time, continued investments in renewables, storage, efficiency, and other carbon emissions-free resources will further reduce the carbon intensity and water usage of the portfolio.

The updated IRP Rule Section 17.7.3.8 (B) (1) requires a description of the resources used by the utility to meet jurisdictional retail load at the time of filing. This information is described in subsequent sections of this chapter, and more comprehensive data is also provided in Appendix H.

4.1.1 Nuclear

Palo Verde Nuclear Generating Station (PVNGS)

PVNGS is a three-unit nuclear power plant located west of Phoenix that went into service between 1986 and 1988 and is operated by Arizona Public Service Company (APS). The plant is jointly owned by several western utilities, whose shares are outlined in Table 18. Under its current licenses, granted by the Nuclear Regulatory Commission in 2011, permit the units to remain in operation through 2045 (Unit 1), 2046 (Unit 2) and 2047 (Unit 3).

Table 18. PVNGS capacity rights by unit as of the end of 2024 (net dependable summer capacity)

Owner	Unit 1 (MW)	Unit 2 (MW)	Unit 3 (MW)	Percentage
Arizona Public Service	382	382	382	29.1%
Salt River Project	333	240	230	20.1%
El Paso Electric	207	208	207	15.8%
Southern California Edison	207	208	207	15.8%
Public Service Co of New Mexico	**30**	**124**	**134**	**7.6%**
So. Cal. Public Power Assoc.	77	78	77	5.9%
Los Angeles Dept. of Water & Power	75	75	75	5.7%
Total	**1,311**	**1,314**	**1,312**	**100.0%**

PNM's current capacity rights total 10.2% of the rated output of each of the three units but declines to 7.6% by the end of 2024. Current capacity rights originated as follows:

- In 1985 and 1986, PNM undertook sale/leaseback financing of Unit 1 (134 MW) and Unit 2 (134 MW) holdings. These units were placed in service during 1986. Since then, PNM has reacquired ownership rights to 154 MW of this lease-financed capacity (30 MW in Unit 1 and 124 MW in Unit 2).
- The remaining leases for PVNGS Unit 1 (104 MW) and Unit 2 (10 MW) originally had terms that expired in 2015 and 2016. PNM exercised options to extend the leases for Units 1 and 2 to January 15, 2023, and January 15, 2024, respectively. Under the leases, PNM had an option to purchase the capacity at fair market value upon the expiration of the leases. In April 2021, PNM filed to abandon leased interests in PVNGS upon their expiration. This filing demonstrated that a scenario without the purchase of the lease interests produced a more favorable cost outcome for customers when compared with a scenario in which the capacity is purchased.
- PNM owns a 134 MW share of PVNGS Unit 3, with no lease provisions. This capacity will be available to meet jurisdictional customer demand into 2047.

This IRP assumes any leased capacity that expires during the planning period is taken out of the existing mix of generation. Accordingly, in this analysis, capacity rights to the PVNGS plant decrease from 402 MW today to 288 MW by the end of 2024.

To deliver electricity from PVNGS to retail loads in New Mexico, PNM relies on jointly owned transmission facilities and contracted transmission rights. 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. Transmission rights and long-term fuel contracts are expected to extend throughout the planning period.

4.1.2 Coal

Through 2022, PNM's portfolio included ownership shares of two large coal plants: San Juan Generating Station and Four Corners Power Plant. Key statistics on these plants and their operations during the 2022 calendar year are shown in Table 19. On September 30, 2022, SJGS ceased operations. The closure of this plant means that PNM's share of FCPP is the only remaining coal resource in the portfolio.

Table 19. Summary statistics for existing coal-fired resources (based on 2022 historical operations)

Facility	Installed Capacity (MW)	Annual Net Generation (MWh)	Capacity Factor (%)	Total CO2 Emissions (short tons)	Carbon Intensity (lbs/MWh)	Water Use (000 gallons)	Water Use Intensity (gal/MWh)
Four Corners	200	1,303,229	74%	1,394,782	2,141	824,595	633
San Juan[A]	562	2,073,062	42%	2,721,277	2,625	1,209,640	584
Total	**762**	**3,376,291**	**55%**	**4,116,060**	**2,438**	**2,034,235**	**603**

Table Notes

A. San Juan Generating Station Units 1 & 4 were retired in June 2022 and September 2022, respectively.

Four Corners Power Plant (FCPP)

FCPP, located in Fruitland, New Mexico, consists of two coal-fired units (Units 4 and 5) that are operated by Arizona Public Service Company (APS). FCPP is located on Navajo Nation reservation land in the northwest corner of the state. The two units are supplied with coal from the Navajo Mine adjacent to the plant under a long-term fuel supply agreement with the Navajo Transitional Energy Company (NTEC) that expires in 2031. PNM's 13% share of these units, acquired in 1969 and 1970 respectively, totals 200 MW of baseload capacity. PNM relies on its transmission system to deliver this power from northern New Mexico to loads in PNM's service territory. Table 20 shows the ownership by generating unit at the FCPP.

Table 20. Current FCPP ownership shares (summer net dependable capacity)

Owner	Unit 4 (MW)	Unit 5 (MW)	Total (MW)	Percentage
Arizona Public Service	485	485	970	63%
Public Service Co of New Mexico	**100**	**100**	**200**	**13%**
Salt River Project	77	77	154	10%
Tucson Electric Power	54	54	108	7%
Navajo Transitional Energy Company	54	54	108	7%
Total	**770**	**770**	**1,540**	**100%**

On January 8, 2021, PNM filed to transfer ownership of its share of FCPP to NTEC at the end of 2024. In that filing, PNM demonstrated that this transaction is in the economic interests of customers and helps to accelerate transition toward a lower carbon emissions portfolio – the latter by both eliminating the most carbon-intensive resource remaining in the portfolio and replacing it with new resources largely composed of carbon emissions-free generation. To support the filing for abandonment of FCPP, PNM analyzed two alternative scenarios: one that retains FCPP in the portfolio through the end of its contract term in 2031 and a second that assumed the transfer of the plant to the NTEC at the end of 2024. Both scenarios adhered to the requisite environmental and reliability criteria of the planning processes. PNM's analysis across a broad range of sensitivities indicated that transferring PNM's ownership share to NTEC at the end of 2024 would have saved customers a net present value of between $30 and $300 million dollars.

On December 15, 2021, the NMPRC denied PNM's application to abandon FCPP. PNM subsequently appealed this decision to the New Mexico Supreme Court, where the Supreme Court upheld the NMPRC's decision. As a result, this IRP utilizes a planning assumption that FCPP will remain in the portfolio through its closure in 2031. However, PNM will actively continue to pursue opportunities that provide benefits to its customers, which may include future filings for early exit of FCPP.

4.1.3 Natural Gas

The portfolio of natural gas generators includes six utility-owned units and one under long-term contract. These gas generators are generally located in two parts of the state: in the south along the El Paso Natural Gas southern mainline, which provides direct access to the low-cost gas supplies of the Permian Basin; and further north close to the largest load center in Albuquerque, where they provide crucial reliability support services to meet demand in a transmission constrained load pocket as well as support transmission system reliability. Table 21 summarizes key statistics for these resources based on their 2022 operations.

Table 21. Summary statistics for existing natural gas resources (based on 2022 historical operations)

Facility	Installed Capacity (MW)	Annual Net Generation (MWh)	Capacity Factor (%)	Total CO2 Emissions (short tons)	Carbon Intensity (lbs/MWh)	Water Use (000 gallons)	Water Use Intensity (gallons/MWh)
Afton	235	820,093	40%	401,251	979	69,708	85
La Luz	41	6,189	2%	4,647	1,502	108	52
Lordsburg	86	72,920	10%	45,055	1,236	22,241	305
Luna	190	752,518	45%	318,051	845	156,030	207
Reeves	146	199,576	16%	158,052	1,584	152,180	762
Rio Bravo	149	263,079	20%	184,414	1,402	1,034	4
Valencia	155	80,327	6%	50,001	1,245	1,313	18
Total	**1,002**	**2,194,702**	**35%**	**1,161,471**	**1,058**	**402,614**	**183**

Fuel supply requirements for natural gas generating plants are assessed 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.

PNM expects to retire most or all of these plants by the end of 2039 to enable the final transition to a carbon-free generation portfolio.[21] Two of these plants, Lordsburg and La Luz, use modern aeroderivative turbine technology and are potential candidates for conversion to hydrogen fuel. In certain scenarios, the IRP assumes these plants remain in service beyond 2040 and are converted to consume hydrogen instead of natural gas. Similarly, Afton is a potential candidate

[21] To meet the 2040 goal, modeling assumes depreciation schedules for all carbon-emitting resources that complete by 2039; however, this depreciation schedule has not been approved for rates at this time. However, PNM will need to reevaluate this based on feedback of the Recommended Decision issued by the NMPRC Hearing Examiner on December 8, 2023.

for conversion to Carbon Capture and Storage (CCS) technology that may allow it to continue operating beyond 2039.

Afton Generating Station

The Afton Generating Station (Afton) is a 235 MW natural gas-fired generating plant that began operating in 2007. Afton is located near La Mesa, New Mexico, within PNM's southern 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 just the 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 existing contracted transmission rights. Natural gas is transported and delivered to the Afton facility via the El Paso Natural Gas Company's southern main line. PNM assumes that Afton will be available to meet customer load through 2039, Afton's planned retirement year, unless converting it to utilize CCS technology to comply with PNM's carbon-free goal is recommended.

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 near Albuquerque. Consisting of a single GE LM6000 aeroderivative combustion turbine, La Luz can deliver 41 MW of capacity into the northern New Mexico load pocket. 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. In the future, the La Luz aeroderivative turbine may be a candidate for conversion to hydrogen combustion, and in scenarios that are designed to include hydrogen as a carbon-free fuel, full conversion is assumed to be achievable by 2040.

Lordsburg Generating Station

Lordsburg Generating Station (Lordsburg) is a natural gas-fired peaking facility located near Lordsburg, New Mexico that came online in 2002. Lordsburg has two GE LM6000 aeroderivative combustion turbines that can deliver a total of 85 MW of peaking capacity. Its quick-start capability assists with system load balancing and regulation. Located in the southern load pocket, energy from Lordsburg can be delivered to southern New Mexico loads or can be delivered via contracted transmission rights to PNM's northern load.

Lordsburg currently receives natural gas supply via the El Paso Natural Gas southern main line. Like La Luz, Lordsburg's aeroderivative turbines present the option for conversion to hydrogen. In this analysis, PNM assumes full conversion is possible by 2040.

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 combustion turbines, each connected to a heat recovery steam generator. PNM owns one-third, or 190 MW, of Luna. Tucson Electric and Samchully Power & Utilities 1, LLC each also own one-third interests in Luna. 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. Luna receives natural gas supply via the El Paso Natural Gas southern main line in New Mexico. Each owner purchases its own fuel supply. PNM's share of Luna is currently expected to be available through 2039, Luna's current planned retirement year.

Reeves Generating Station

The Reeves Generating Station is located in central Albuquerque. The 146 MW facility is a natural gas steam electric plant with three units. Units 1 & 2, 42 and 41 MW steam turbine generators, became operational in 1958 and 1962, respectively; Unit 3, a 63 MW steam turbine, became operational in 1962. It operates on natural gas supply delivered through the New Mexico Gas Company. 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 costs needed to reach the end of the plant's depreciable life in 2030.

PNM operates the Reeves Generating Station not only to meet generation requirements, but also to relieve transmission constraints, ensure transmission criteria is met during certain operating conditions, and provide system voltage support, making it a crucial resource in PNM's portfolio. Replacing this with sufficient carbon-free resources and addressing needed transmission improvements will be a key consideration in the next IRP.

Rio Bravo Generating Station

Rio Bravo Generating Station is a natural gas-fired generating plant with a capacity of 149 MW located on the south side of Albuquerque. This station consists of a GE heavy frame 7FA combustion turbine that went into service in 2000. In June 2013, the NMPRC approved an application for PNM to acquire the plant from its previous owner.

Rio Bravo's location within the northern New Mexico load center makes it is an important PNM load-side generating resource to relieve transmission system constraints, ensure transmission operating criteria is met during certain operating conditions, and provide voltage support. Rio Bravo is a dual-fuel facility. It primarily operates on natural gas supply delivered through the New Mexico Gas Company. However, when required, the plant can operate on fuel oil supplied under a delivery service agreement and stored on-site. PNM anticipates that Rio Bravo will be available to meet customer load through 2039, the plant's planned retirement year, as long as resource adequacy and transmission system operation requirements are met.

Valencia Energy Facility

The Valencia Energy Facility (Valencia) is located south of Belen, New Mexico near Albuquerque in the northern load pocket. It consists of a heavy-frame GE 7FA gas turbine that began commercial operations on May 30, 2008. Valencia supplies PNM with approximately 155 MW of peaking capability under a 20-year power purchase agreement (PPA) with Southwest Generation, LLC. The PPA expires in 2028. PNM will review options for potential replacement as the expiration date nears. Valencia receives its natural gas fuel supply through a four-mile-long pipeline interconnection to Transwestern's interstate pipeline.

4.1.4 Geothermal

The Dale Burgett Geothermal Facility 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 renewable energy credits (RECs) under a 20-year PPA with Cyrq Energy. PNM began purchasing power from this facility in January 2014. Initially, operations began at the 4 MW level, increasing its net capacity up to 11 MW in 2018.

The plant uses a closed-loop binary system, in which 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 a turbine expander to generate electricity and is then cooled and condensed back into a liquid for recirculation. The groundwater is re-injected into the same deep reservoir to be naturally reheated without ever contacting the secondary working fluid or being exposed to air.

4.1.5 Wind

PNM currently has power purchase agreements for 658 MW of total wind capacity across five facilities: the New Mexico Wind Energy Center (NMWEC), Red Mesa, Casa Mesa, and La Joya 1 & 2. In an average year, these resources can produce an annual output of 2,200 GWh, enough to meet over 20% of PNM's present energy needs. The output of wind resources can fluctuate significantly on a year-to-year basis due to natural variability in meteorological patterns. For instance, since 2003, NMWEC's annual capacity has averaged 29% but has ranged as low as 23% and as high as 35%. Table 22 shows historical generation from the five wind facilities. The increase in capacity factor for NMWEC in 2019 is due to repowering of the facility. Additionally, the recent additions of Casa Mesa and La Joya took advantage of advances in wind turbine technology and construction to achieve higher capacity factors, approaching or exceeding 40%.

Table 22. Ten-year history of PNM's wind resource performance

Energy (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Casa Mesa	-	-	-	-	-	-	187,441	187,442	191,070	163,498
La Joya 1	-	-	-	-	-	-	-	-	560,453	555,817
La Joya 2	-	-	-	-	-	-	-	-	384,857	446,022
NMWEC*	493,949	489,442	404,765	492,427	496,778	485,108	610,138	573,382	611,353	577,112
Red Mesa	-	-	184,297	214,030	215,606	212,754	220,073	230,275	196,105	197,568
Total	**493,949**	**489,442**	**589,062**	**706,457**	**712,384**	**697,862**	**1,017,652**	**991,099**	**1,943,838**	**1,940,017**
Capacity Factor (%)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Casa Mesa	-	-	-	-	-	-	43%	43%	44%	37%
La Joya 1	-	-	-	-	-	-	-	-	39%	38%
La Joya 2	-	-	-	-	-	-	-	-	31%	35%
NMWEC*	28%	28%	23%	28%	28%	28%	35%	33%	35%	33%
Red Mesa	-	-	21%	24%	24%	24%	25%	26%	22%	22%
Total	**28%**	**28%**	**22%**	**27%**	**23%**	**23%**	**33%**	**32%**	**34%**	**33%**

** Increased output from NMWEC in 2019 due to repowering*

Output from PNM's wind resources also fluctuates from hour to hour and day to day, but these typically exhibit some consistent trends. Figure 44 shows the average hourly production pattern for each month of the year. For instance, wind resources tend to generate less output in summer than in other seasons, and more output in the evening and nighttime than during the day. This trend complements solar which is strongest in the spring summer days; it is common for wind output to increase just as solar output declines, though the scale and timing of this is subject to the variability of these resources. During the hours of typical peak period, wind resources often generate at capacity factors between 10-30%, which limits their ability to contribute to system reliability.

Figure 44. Historical average capacity factor by month and time of day for PNM's wind resources (2022)

		Hour of Day																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Month	Jan	45%	44%	44%	45%	44%	45%	44%	44%	39%	35%	36%	35%	36%	37%	39%	38%	39%	42%	46%	46%	47%	48%	48%	46%
	Feb	47%	45%	41%	40%	39%	38%	36%	35%	33%	33%	32%	33%	37%	40%	41%	41%	43%	41%	42%	45%	47%	46%	46%	45%
	Mar	45%	40%	39%	37%	35%	34%	33%	29%	27%	29%	32%	34%	37%	40%	42%	43%	44%	45%	45%	48%	49%	49%	48%	46%
	Apr	56%	55%	52%	49%	47%	45%	41%	39%	42%	45%	45%	46%	50%	51%	52%	55%	56%	57%	55%	55%	59%	59%	56%	55%
	May	41%	39%	35%	35%	33%	31%	30%	29%	31%	35%	37%	39%	40%	44%	46%	52%	53%	53%	50%	49%	52%	49%	45%	44%
	Jun	34%	32%	31%	32%	31%	27%	23%	22%	22%	21%	21%	23%	25%	28%	32%	34%	34%	38%	38%	36%	37%	37%	37%	34%
	Jul	25%	23%	21%	20%	19%	17%	13%	10%	10%	8%	6%	6%	11%	12%	14%	20%	25%	28%	29%	29%	31%	29%	26%	26%
	Aug	16%	15%	14%	15%	16%	15%	13%	11%	12%	14%	14%	14%	15%	18%	21%	22%	22%	23%	23%	25%	25%	21%	19%	19%
	Sep	26%	25%	25%	23%	23%	23%	20%	15%	15%	14%	14%	15%	17%	20%	23%	26%	27%	25%	30%	33%	33%	32%	30%	27%
	Oct	28%	26%	26%	23%	22%	22%	22%	20%	20%	22%	22%	23%	25%	28%	30%	32%	33%	32%	32%	32%	33%	30%	28%	29%
	Nov	35%	34%	35%	35%	35%	34%	33%	32%	31%	35%	35%	37%	37%	37%	39%	39%	38%	39%	40%	39%	39%	39%	38%	38%
	Dec	41%	39%	40%	41%	40%	42%	40%	41%	40%	39%	42%	43%	43%	44%	43%	43%	45%	47%	43%	41%	41%	43%	39%	41%

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's Blackwater-Clines Corners 345-kV transmission line at the Taiban Mesa substation in eastern New Mexico and can deliver up to 200 MW into PNM's system. Since 2003, PNM has purchased the renewable energy and the associated RECs generated by the NMWEC from its owner and operator, NextEra Energy, Inc. In 2019, this facility was repowered to increase output, and PNM extended the PPA through 2044.

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.

Casa Mesa

The Casa Mesa wind facility is a 50 MW facility located in De Baca and Quay Counties, New Mexico. Owned and operated by NextEra Energy, Inc., the facility is adjacent to NMWEC and utilizes the same 200 MW interconnection with PNM's system, so the combined output from both Casa Mesa and NMWEC is limited to 200 MW. PNM has purchased the energy and associated RECs generated by this facility since January 1, 2018, under a 25-year PPA that expires in 2043.

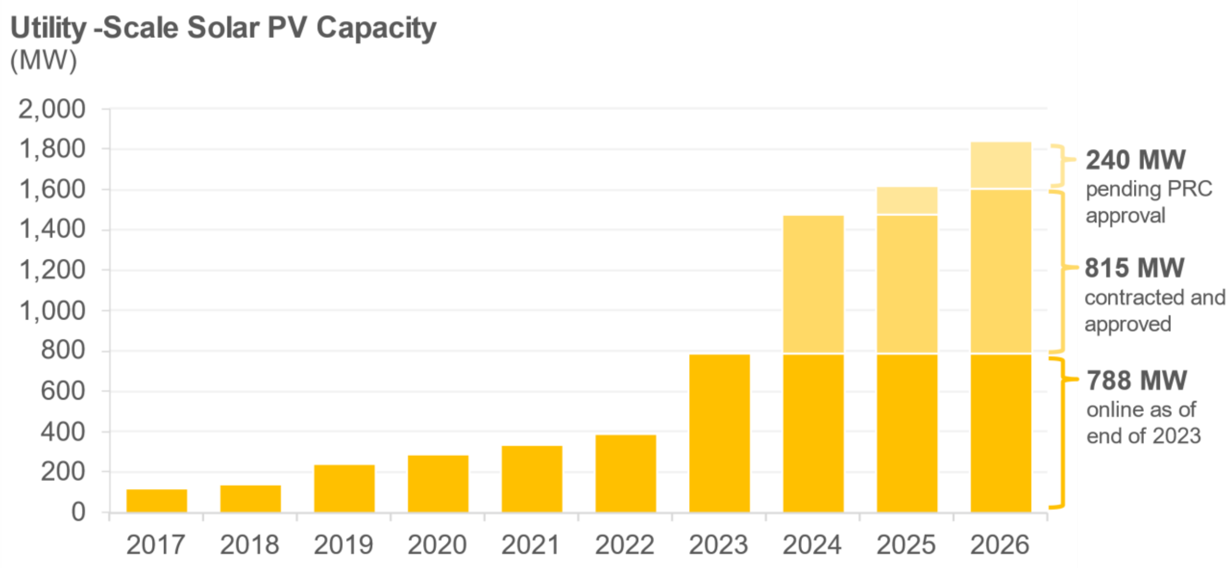
La Joya Wind 1 & 2

La Joya 1 & 2 are 166 MW and 140 MW facilities, respectively, located in Torrance, New Mexico. These plants came online in 2020 and 2021 and are owned by Avangrid Renewables, who sells the output to PNM under two separate long-term PPAs that expire in 2040. Output from La Joya 1 is designated to meet voluntary customer renewable programs and therefore is not considered an RPS-eligible resource for compliance with the ETA; output from La Joya 2 serves retail customers and provides RECs for statutory RPS obligations.

4.1.6 Solar

PNM's current portfolio of solar PV resources includes a total of over 1,800 MW of nameplate capacity, sufficient to meet roughly 20% of current annual energy needs; 788 MW are currently operational as of the end of 2023 and an additional 1,055 MW are contracted and under development. A large portion of existing solar PV resources have been added to the system in the past several years; the growth of the portfolio of solar resources over time is shown in Figure 45. These solar PV resources consist of a mix of fixed-tilt and single-axis tracking arrays 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. A list of all the existing solar PV facilities under PNM ownership and long-term contract is provided in Appendix H.

Figure 45. Growth of solar PV installed capacity owned by and under contract to PNM



The past few years and the next several years are a period in which PNM's solar PV portfolio is rapidly growing. This increase in capacity is due to the procurement of several large-scale solar PV projects to meet specific needs, a number of of which will be collocated with storage resources discussed in Section 4.1.7:

- **SJGS Replacement Resources:** The NMPRC originally approved four new solar PV facilities as part of a portfolio of replacement resources for SJGS. All four of these projects experienced project development challenges and did not come online as originally planned; PNM provided regular updates to the NMPRC on the status of these projects. Of these four, one contract was terminated (Rockmont Solar, 100 MW), one is expected to be operational (Jicarilla Solar I, 50 MW) by the end of 2023, one is operational at partial capacity and is expected to reach full capacity by the end of Q1 2024(Arroyo Solar, 300 MW), and one is expected to come online in 2024 (SJGS Solar I, 200 MW).
- **New Resources to Serve Large Customer Loads:** Two new solar PV plants totaling 330 MW are under development to serve the needs of a specific large customer. These facilities are expected to come online in 2024 (190 MW solar and 50 MW) and 2025 (140 MW solar and 50 MW BESS).
- **PVNGS Replacement Resources:** The Atrisco Solar I plant, a 300 MW facility, was approved by the Commission and is expected to come online in 2024.
- **Community Solar Resources:** A total of 125 MW of community solar PV capacity has been approved by the Commission. Specific projects have not yet been fully determined as of this IRP issuance.

- **2026 RFP Resources:** PNM is currently seeking NMPRC approval of the 100 MW Quail Ranch I solar PV facility, procured through PNM's recent 2026 RFP.

Like wind, solar is an intermittent resource whose output varies hourly and seasonally as a function of meteorological conditions. While the daily production pattern for PNM's solar resources is more regular than wind, its variability, and steep ramps in output during sunrise and sunset hours nonetheless pose a challenge for system balancing on a day-to-day basis. Typical output patterns for PNM's portfolio of solar resources based on historical data from 2022 are shown in Figure 46.

Figure 46. Historical average capacity factor by month and time of day for PNM's solar resources (2022)

Month	Hour of Day: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-	-	-	-	-	-	-	5%	42%	64%	66%	64%	62%	63%	64%	58%	19%	1%	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	15%	54%	67%	70%	70%	71%	71%	68%	63%	40%	6%	-	-	-	-	-	-
Mar	-	-	-	-	-	-	4%	34%	59%	68%	72%	73%	73%	72%	68%	62%	48%	14%	-	-	-	-	-	-
Apr	-	-	-	-	-	1%	28%	72%	83%	87%	87%	86%	86%	85%	82%	77%	66%	31%	2%	-	-	-	-	-
May	-	-	-	-	-	7%	46%	74%	82%	86%	88%	88%	87%	85%	82%	77%	67%	42%	7%	-	-	-	-	-
Jun	-	-	-	-	-	8%	40%	60%	69%	74%	77%	77%	75%	71%	64%	53%	43%	31%	9%	-	-	-	-	-
Jul	-	-	-	-	-	5%	36%	61%	71%	79%	81%	81%	77%	70%	63%	56%	46%	29%	8%	-	-	-	-	-
Aug	-	-	-	-	-	1%	22%	54%	68%	74%	75%	74%	70%	65%	59%	51%	42%	23%	3%	-	-	-	-	-
Sep	-	-	-	-	-	-	15%	56%	74%	80%	81%	80%	77%	74%	70%	61%	42%	11%	-	-	-	-	-	-
Oct	-	-	-	-	-	-	3%	34%	56%	62%	62%	63%	63%	63%	60%	49%	20%	1%	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	20%	56%	66%	65%	63%	63%	64%	62%	46%	9%	-	-	-	-	-	-	-
Dec	-	-	-	-	-	-	-	5%	37%	54%	56%	55%	53%	53%	50%	35%	6%	-	-	-	-	-	-	-

4.1.7 Energy Storage

As of the end of 2023, PNM's portfolio includes two operational energy storage facilities, both procured as part of replacement resources for SJGS and co-located with solar PV facilities of the same name:

- Arroyo Storage, a 150 MW storage facility co-located with the 300 MW Arroyo Solar plant in McKinley County, online in May 2023; and
- Jicarilla 1 Storage, a 20 MW storage facility came online in September 2023 and the co-located 50 MW Jicarilla Solar I plant in Rio Arriba County, is expected to come online in December 2023.

By 2026, the development of projects that have either been approved or are currently pending Commission approval will bring PNM's total storage capacity to nearly 1,000 MW. These include one additional resource from the SJGS replacement portfolio, two resources dedicated to serving large customer loads, the results of PVNGS Replacement and 2026 RFPs, and proposed distribution-level energy storage. These resources are summarized in Table 23.

Table 23. Existing, approved, and proposed battery storage in PNM's portfolio

Category	Plant Name	Capacity (MW)	Status	In-Service Year
SJGS Replacement	Arroyo BESS I	150	Operational	2023
	Jicarilla BESS I	20	Operational	2023
	SJGS BESS I	100	Approved	2024
PVNGS Replacement	Atrisco BESS I	300	Approved	2024

Large Customer	Sky Ranch I	50	Approved	2024
	TAG BESS I	50	Proposed	2025
Distribution	South Coors 12 and Tome 12 Distribution Feeders	12	Proposed	2025
2026 RFP	Quail Ranch I	100	Proposed	2026
	Sky Ranch II	100	Proposed	2026
	Route 66	50	Proposed	2026
	Sandia BESS I	60	Proposed	2026

By the end of 2026, when all approved and proposed resources are in service, the total capacity of battery storage in the portfolio will be 992 MW. This amount of capacity – nearly half of PNM's peak demand – will make PNM an industry leader in the integration of storage into the grid. These resources will provide significant benefits to customers, as PNM's ESAs will allow operators to dispatch them to balance loads and resources in real time to support both renewable integration and reliability needs of the system. At the same time, recognizing the limited history of battery storage at grid scale, PNM plans to monitor their performance closely to ensure that the value that they provide to the systems is aligned with expectations.

4.2 Transmission System

PNM is one of over 60 transmission service providers in the Western Interconnection. As a Transmission Operator and transmission owner, PNM provides open access transmission service under a pro forma FERC tariff to serve the needs of both retail customers and wholesale customers. PNM operates the transmission system within a NERC-certified Balancing Authority area (BAA). PNM monitors key transmission paths within the BAA and interconnections to other BAAs 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 its role as a Transmission Service Provider, PNM serves both retail loads and network customers pursuant to its Open Access Transmission Tariff (OATT) as approved by the Federal Energy Regulatory Commission (FERC). Currently, wholesale customers account for about 50% of the utilization of PNM's transmissions system. These system customers fall into two categories: Network Integration Transmission customers and Point-to-point customers.

PNM's transmission system has undergone dramatic changes in its configuration and uses since its inception. 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, some lines between the cities were 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 a 230 kV line to Four Corners built in 1962, concurrent with the construction of the original FCPP.

Most elements of the 345 kV transmission system that is in place today were developed in the late 1960s and early 1970s, coinciding with the construction of FCPP and SJGS in northwestern New Mexico. To deliver power from these new large baseload facilities to PNM's growing loads in New Mexico's largest cities, PNM developed multiple 345 kV transmission corridors. 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 being limited to peak hours of the summer or when transmission system import limits would otherwise be exceeded.

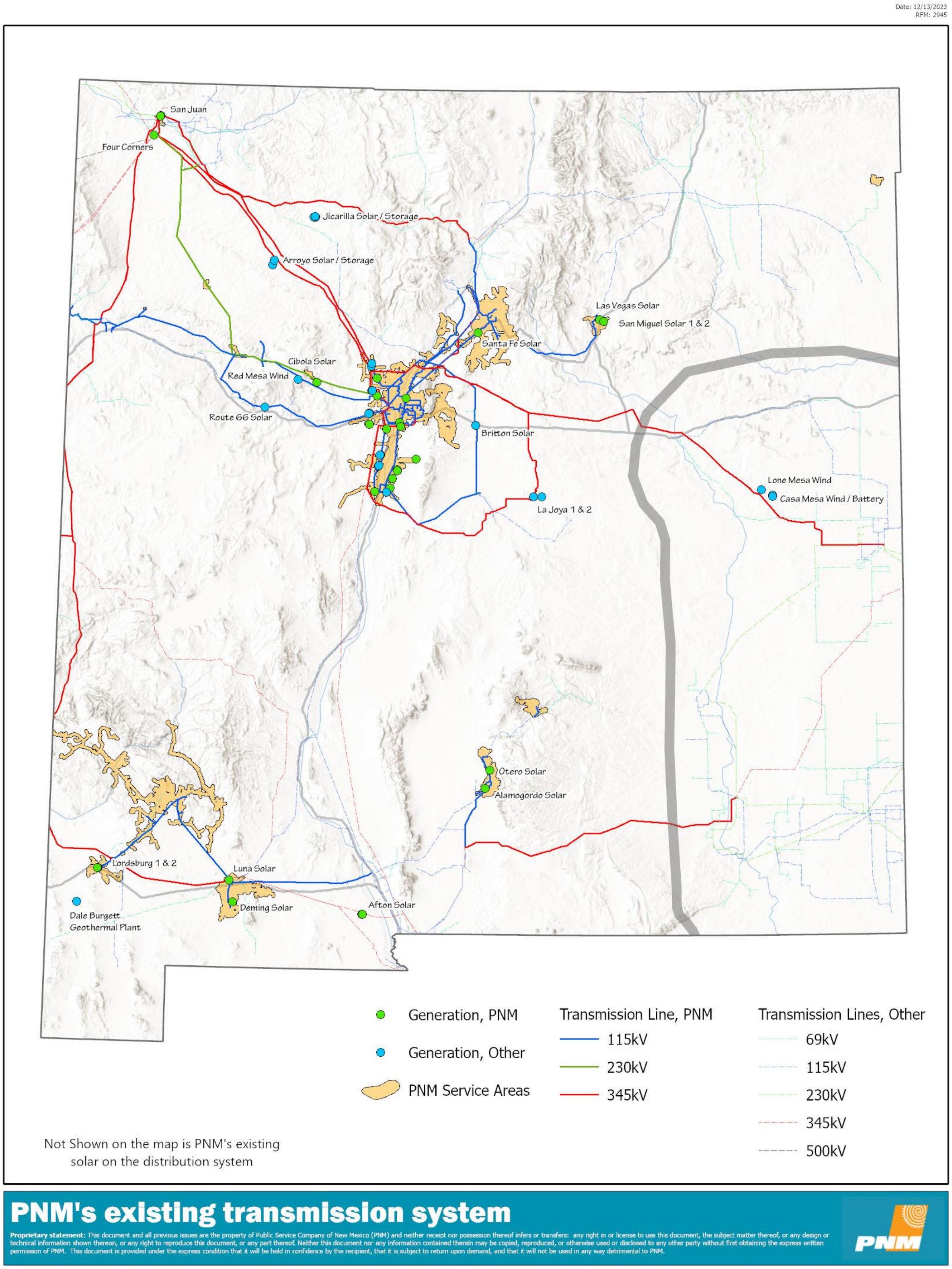
The last PNM backbone transmission line was completed in 1984, when PNM constructed the Eastern Interconnection Project. This line, a 216-mile, 345 kV line from the Placitas area north of Albuquerque located at BA 345 kV Switching Station to Clovis, New Mexico, connected PNM with Southwestern Public Service (SPS) in the Eastern Interconnection 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 and location of resources near the load centers in Northern New Mexico.

Today, the transmission system consists of the 345 kV lines and 230 kV line built in the 60's and 70's that connect the Four Corners area in northwest New Mexico to load centers in the Southeast and South. Power flow on these lines is typically from north to south due to the location of baseload 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. Historically, power has flowed in an easterly and southerly direction on these 345 kV lines. 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.

PNM's existing transmission system is shown in Figure 47 below.[22] The key elements of PNM's existing system are (1) the high voltage backbone between Four Corners and the northern load center, (2) the high voltage transmission lines that link Four Corners with the southern portion of PNM's service territory, and (3) the Eastern Interconnection Project, which has recently been expanded to facilitate delivery of wind resources to PNM's system and beyond.

[22] A full list of PNM transmission lines and switching states appears in Appendix E

Figure 47. Map of PNM's existing transmission system



In addition to these resources, PNM purchases transmission service from several other transmission service providers within the region to allow for the delivery of PNM's generation to serve load. PNM has the right to continue taking long-term firm transmission service in accordance with FERC policy. These agreements are summarized in Table 24.

Table 24. Transmission service agreements with neighboring transmission service providers

Service Provider	Transmission Service Description
Arizona Public Service	PNM contracts with APS for point-to-point service to deliver output from PVNGS to PNM's system: • Non-OATT bilateral contract for 130 MW from Phoenix to Four Corners • OATT transmission service for a total of 145 MW from Phoenix to Four Corners
Tri-State Generation & Transmission	PNM contracts for network service under Tri-State's OATT to serve retail load in the Town of Clayton (a load of approximately 3.5 MW)
El Paso Electric	PNM contracts with EPE for point-to-point services to facilitate transfers between northern and southern New Mexico: • 295 MW to deliver resources from south to north • 25 MW to deliver resources from north to south
Western Area Power Administration	PNM and WAPA have a transmission exchange agreement under which: • WAPA provides 134 MW of service between Phoenix and Four Corners to deliver output from PVNGS to PNM system. • PNM provides 247 MW of service from Four Corners to various New Mexico delivery points

The configuration of PNM's transmission system today, largely designed to deliver power from baseload generators in northwest New Mexico to load centers in the north and south, meeting customers' needs on a dynamic basis. PNM transmission system has started to see changes in the utilization of the transmission system as PNM's portfolio and neighboring utilities transition to more dispersed and diverse types of generation resources. Maintaining, operating, and expanding the transmission system will be crucial to delivering new renewable resources to loads and to enable enhancements and more dynamic participation in the wholesale markets of the Western Interconnection. The importance of planning for this maintenance, operation, and expansion is acknowledged by PNM's Infrastructure Improvement Plan (PIIP) , which plans to invest significant capital to address legacy in the transmission and distribution systems.

In this section, the current dynamics of transmission system are discussed, the expectation of these dynamics to change over the next several years, and any considerations for new expansions to transmission as part of PNM's long-term planning efforts.

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 various portions of the southern New Mexico system, including El Paso Electric's facilities.

Northern Load Center

PNM's ability to meet demands reliably within the northern load area depends on both the transmission system and the generation resources within the load pocket. The existing bulk transmission system alone is not designed with the capability to meet the system's highest demands with resources from outside the load pocket. Accordingly, despite the low-capacity factors of load-side resources, Reeves Generating Station, Rio Bravo, and the Valencia PPA provide crucial capability to ensure reliability, both during peak demand periods and in the event of transmission outages.

Notwithstanding the typically low-capacity factors of load-side resources, the ability to produce electricity at a predictable level across extended periods as needed makes such resources crucial for maintaining local reliability. At the same time, the IRP assumed that the Valencia PPA will expire in 2028 and that Reeves will retire by the end of its depreciable life in 2030. Potential loss of the capabilities provided by these units, PNM will need to evaluate the potential alternatives to ensure reliability is maintained through investment in new load-side resources, new transmission, or a combination of the two.

Southern Transmission System

PNM's southern New Mexico system delivers power to a combination of jurisdictional service territories which include Deming, Silver City, Lordsburg, Alamogordo, Ruidoso, as well as to Northern New Mexico. The southern New Mexico system also contains three solar facilities and three natural gas fired generation facilities at Afton, Luna, and Lordsburg . In addition to PNM's ownership share in the WECC Rated Transmission - Path 47, PNM purchases transmission service 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 and Silver City areas. PNM also purchases transmission service from EPE and TEP to move a portion of southern New Mexico generation to northern New Mexico.

Afton, Luna, and Lordsburg generation resources provide a total of 510 MW of capacity. Because they are located inside the WECC Rated Transmission - Path 47 transmission boundary, these resources can adequately serve loads in southern New Mexico. Power delivery rights over a combination of PNM, Tri-State, and EPE assets combine for 345 MW of transmission rights from southern New Mexico to northern New Mexico that allow this generation to serve loads in the north 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 has rights to approximately 75 MW of transmission resources for delivering power from northern New Mexico to southern New Mexico across the Path 47 transmission boundary.

Four Corners Area

The transmission lines connecting the Four Corners area to the load center in Albuquerque has been the historical backbone of the PNM transmission system. This part of PNM's system was designed to transmit the baseload output from SJGS, FCPP, and PVNGS to PNM's largest load center in Northern New Mexico.

While the capacity provided by these lines remains crucial for meeting peak demands reliably, the utilization of this part of PNM's transmission system has changed notably with recent additions of intermittent renewable resources in northern and eastern New Mexico. Increased delivery of renewable energy into the northern New Mexico load pocket has led to reduced flows on the system between Four Corners and Albuquerque – and, in some instances, the prevailing historical direction of flow has reversed during periods of high renewable production. This operational trend is expected to continue.

By 2031, PNM plans include abandonment of FCPP (200 MW) and the expiring leases of PVNGS (114 MW). These abandonments potentially free up a similar amount of capacity from the transmission system that can be repurposed to enable development of future resources in the northwestern part of the state.

The headroom on the transmission system created by the 2022 abandonment of SJGS will largely be exhausted by the portfolio of solar and storage replacement resources approved by the NMPRC in Case No. 19-00195-UT. However, the future abandonments of FCPP and leased shares of PVNGS will create additional headroom on the transmission system. PNM's planning efforts assume that these abandonments enable up to 314 MW of existing transmission to be repurposed for new resource development by 2025.

Eastern New Mexico

Development of wind resources in eastern New Mexico has resulted in the expansion of the transmission capacity out of eastern New Mexico. The high-quality resources present in the eastern part of the state have attracted interest from developers and off-takers outside the state of New Mexico, and a significant amount of the new capacity contemplated would contribute to the clean energy goals of neighboring western states. To date, PNM and merchant transmission developers have together undertaken significant expansions to the Eastern New Mexico transmission system to enable interconnection of these resources.

In New Mexico, wind resources in the eastern portion of the state currently include 250 MW connected at Taiban Mesa serving PNM loads, 90 MW connected at Guadalupe serving Arizona loads, and approximately 790 MW connected at Blackwater and Clines Corners serving California loads. These resources 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). An additional wind farm injecting 306 MW of generation at Clines Corners enabled by the completion of a second 345 kV line between Clines Corners and PNM's BA Switching Station, known as the BB2 line. The addition of this wind farm, along with the existing wind farms, has resulted in 1362 MW of firm transmission service between Clines Corners and BA Station.

In December 2021, the Western Spirit Transmission Project was completed and energized, allowing for the interconnection of an additional 800 MW of wind resources to be transmitted across PNM's system. The project was developed by Pattern Energy and was acquired by PNM upon completion. The project was fully subscribed upon initial energization and allowed total wind resources in eastern New Mexico to be expanded to approximately 2400 MW.

West of Albuquerque

To the West of Albuquerque, roughly 150 MW of existing generation rely on PNM's transmission system to meet PNM and Network Transmission Customer loads in Northern New Mexico. With the addition of PEGS Solar (TSGT), this portion of the transmission system is fully subscribed.

South of Albuquerque

In Valencia County, South of Albuquerque, approximately 250 MW of existing resources are delivered into the northern load center over the existing system. Like other parts of the transmission system, this portion of the transmission system is fully subscribed. Additional resources for Sky Ranch (190 MW Battery and BESS) are currently under construction and expected to be energized, along with associated upgrades to the transmission system in the area, in 2024 to serve additional large customer loads in the area.

4.3 Distribution System

PNM maintains an extensive distribution system to bring safe, reliable power from the large generation and transmission sources to customers' homes and businesses. Distribution services are provided by overhead and underground conductors that are interconnected to substations and serve load centers via feeder circuits. Specific services are then connected to distribution transformers that reduce the voltage to the prescribed service level. Each service location has a meter that enables PNM to measure attributes of the power delivered, including consumption. Distribution infrastructure, including transformers, conductor, and meters, requires continued investment to ensure that electrification and distributed generation can be effectively managed as customer energy profiles evolve.

PNM's PIIP effort also addresses the distribution system to enhance customer satisfaction and system reliability, proactively addressing aging assets, and increasing grid resiliency. This long-term asset management plan drives associated investments in PNM's capital investment plan based on project prioritization, alignment with system capacity plans derived from distribution area plans, and field reports of asset performance. Investments for addressing aging infrastructure as part of a comprehensive approach will ensure the core assets are better prepared to meet the decarbonization goals set in New Mexico while continuing to support customer expectations.

PNM filed its Grid Modernization Plan in October 2022 (Case No. 22-00058-UT) and subsequent cost-benefit analysis of this plan in November 2023, seeking to modernize its distribution grid to align with the carbon free requirements of New Mexico's Energy Transition Act. PNM's Grid Modernization Plan is an 11-year plan with planned investments of $344 Million in capital in the first six years. PNM's Grid Modernization Plan will enable customers to become partners in the transition to carbon free and maintain the service quality customers expect.

To develop its file Grid Modernization Plan, PNM collaborated with third party industry leaders to build a "Guide for PNM's Grid Modernization Implementation" which included input from numerous customer outreach events. The U.S. Department of Energy Modern Distribution Grid, Volumes I, II, III, & IV, were leveraged collectively to guide the development of PNM's implementation plan for grid modernization. In collaboration with other third-party experts, PNM built a "Distribution Technology Roadmap" to develop a technology deployment for the six-year Grid Modernization Plan and performed a cost-benefit analysis, a "PNM 2040 DER Integration Plan" with the goal of safely and reliably integrating high penetrations of distributed energy resources (DERs) into PNM's distribution grid.

PNM also initiated efforts to determine the sizing and feasibility of battery installations on distribution feeders to increase solar interconnections on the distribution system. This study provided the basis for the first two distribution battery installations, which came before the Commission in an application which was filed on May 3, 2023 in Case No. 23-00162-UT.

Each of these studies or plans provides an active roadmap for PNM's distribution system to support the New Mexico energy transition, aligning with key datasets and inputs in the PNM Integrated Resource Plan. For example, PNM utilized the behind the meter solar forecast by 2040 as a key forecast to establish the PNM 2040 DER Integration Plan with the goal of accommodating customer DERs in a safe, reliable, and resilient manner.

PNM's Grid Modernization Plan will convert PNM's traditional "one-way" distribution system that currently delivers energy from generators to customers to a "two-way" distribution system where customers are active participants. This transition comes at a time when customers have shown increasing interest in both self-generation and electrification, each of which benefit from a modernized grid. New loads and resources will be connected to existing distribution networks, which were not necessarily built 30+ years ago with BTM generation, electric vehicles, and electric heating in mind. Technologies in PNM's Grid Modernization Plan support the two-way grid as PNM customers integrate solar and storage with new electric loads. PNM, as the system Orchestrator, can also keep the system in balance by leveraging insight into real-time grid conditions on the distribution system through modernizing its distribution grid.

PNM is committed to maintaining reliability and resiliency through the energy transition at reasonable rates. PNM's PIIP plans, paired with its Grid Modernization Plan and distribution battery efforts, are all integral parts of the transition to carbon free by 2040. Leveraging customer DERs and enabling customer participation are key building blocks of the transition that will optimize the existing grid infrastructure.

The System Average Interruption Duration Index (SAIDI) is an industry term used to describe the average length of time, measured in minutes, that power outages are experienced by customers across the entire system each year. Ultimately, this metric is useful to understand the performance of PNM's transmission and distribution system. PNM formulates operating plans to maintain SAIDI as low as reasonably achievable. In 2022, PNM's SAIDI was 101.3 minutes.

4.4 Critical Facilities and Infrastructure

PNM maintains contingency resources to ensure reliable service in the event of an unanticipated failure of critical facilities and infrastructure. System risks evolve as the system and PNM's portfolio change. To address system risks, PNM has a designated Crisis Management and Resilience function to establish and maintain a capability that plans for and effectively manages rapidly evolving crises that pose a strategic or operational threat to PNM's system reliability, infrastructure, personnel, or customers. This is to implement an enterprise "All Hazards" response plan and business continuity program to establish the framework for how the utility responds to and maintains operational resilience during any emergency.

PNM currently maintains hazard and business area-specific response and continuity plans, focusing on areas that present unique challenges, such as storms and other severe weather events, wildfires, cyberattacks, and pandemics. PNM performs hazard and impact assessments of its infrastructure based on industry standards, best practices, and a tiered approach focusing on greatest risk to safety, security, and service reliability. Further, PNM works with the utility industry in support of state & federal efforts to prepare for possible disruption of electric systems. This includes disaster planning, coordination of grid recovery & resilience, generation resource adequacy and fuel supply security.

5 Analytical Approach

Chapter Highlights
• This chapter presents the analytical approach used to develop the MCEP, including a discussion of the scenario approach, the inputs and assumptions needed for analysis, and the tools used to complete the analysis. • This IRP analysis uses a scenario-based framework to study the performance of several different options for meeting future needs under a wide range of conditions; scenarios are designed to highlight different technology pathways and carbon intensity trajectories to achieve PNM's 2040 goals while maintaining reliability. • To develop and evaluate a range of potential plans, PNM utilizes two industry-leading modeling tools: (1) SERVM, a loss-of-load-probability simulation model, and (2) EnCompass, which provides both long-term capacity expansion and production cost modeling. These two tools complement one another: SERVM provides a very detailed accounting of system reliability needs and the contributions of various resources to them and EnCompass allows for the least-cost optimization of a portfolio of resources over a long-time horizon. • In addition to the quantitative analysis conducted in these tools, PNM considers a range of risk factors qualitatively in developing its plan.

To achieve the objectives outlined above, PNM relies upon a robust analytical framework that builds upon and enhances the methods used in previous IRPs to conduct extensive scenario analysis. The focus of this year's plan on the transition to a carbon-free portfolio presents a number of uniquely challenging issues, none more significant or conspicuous than the question of how PNM might achieve this goal while maintaining reliability. To ensure answers to this and other questions are robust, PNM employs sophisticated software to optimize the portfolio while accounting for resource adequacy needs. This section describes these components to help identify the Most Cost Effective Portfolio (MCEP) from the modeling results.

5.1 Scenario Analysis Framework

PNM's framework of scenarios, futures, and sensitivities serve to focus the analysis so that modeling results provide insight to the most important questions. This section describes how each of these pieces fit into the analysis, and what specific scenarios, futures, and sensitivities are tested.

- A **scenario** explores a specific choice or set of choices that PNM must evaluate in an effort to balance cost, environmental, and reliability objectives. In this IRP, the different scenarios are oriented around different sets of options for future generation resources, with a particular focus on the roles different types of resources can play in helping meet medium-term reliability needs as large existing plants exit the portfolio.
- A **future** is a combination of forecasts and projections that, together, define a complete and coherent worldview of how external forces may shape the world. Key parameters that characterize different futures in the planning process are the level of load growth expected in the service territory, future changes in commodity and carbon prices, and the long-term trajectories of technology costs.

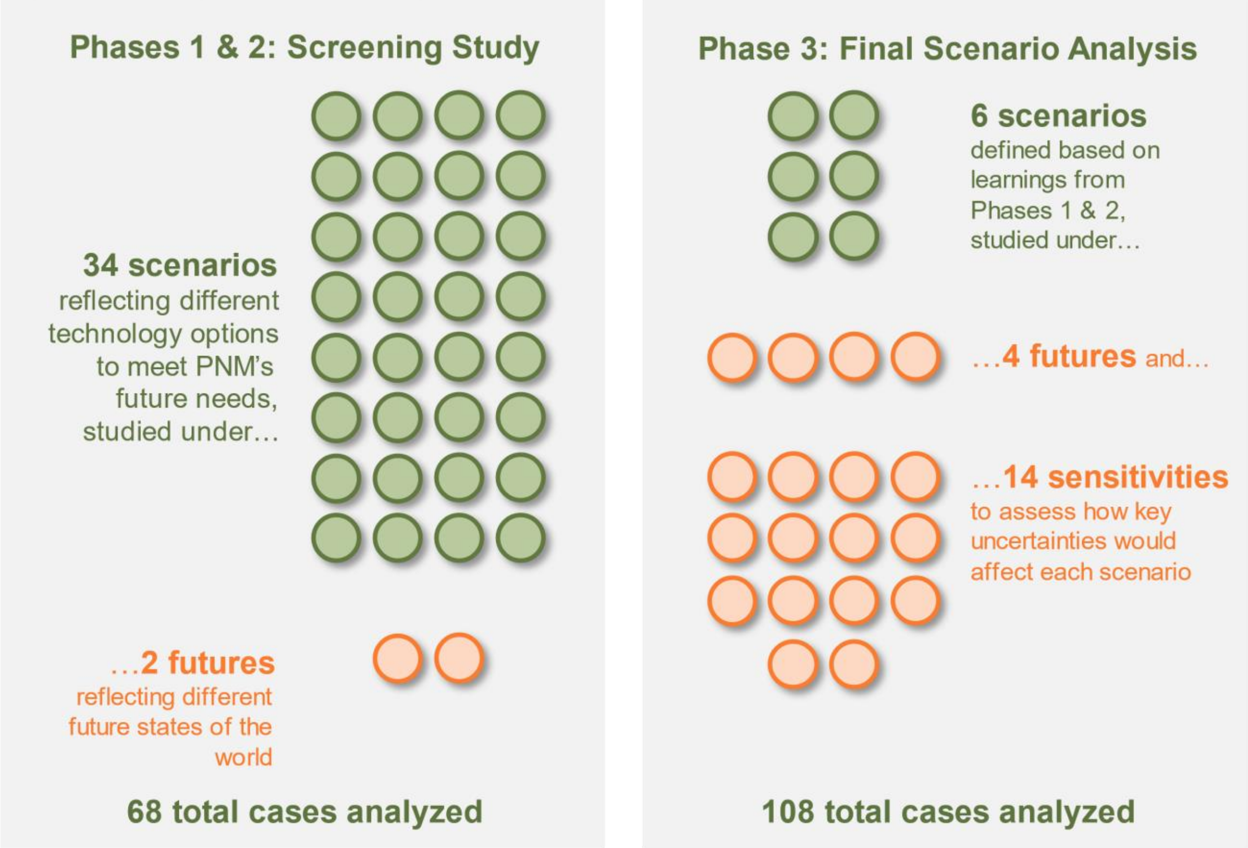
- A **sensitivity** is a variation on a future in which one single element is changed. Sensitivities help to understand the risks in planning the portfolio by showing how much the portfolios would adjust under alternative assumptions, as well as how significant the impact of that uncertainty is to maintain low cost of service.

For this IRP, PNM's development and analysis of future resource portfolios has been split into occurred across three phases:

1. **Phases 1 & 2:** two phases of screening analysis, in which a wide range of scenarios are examined to better understand the potential roles of different types of resources and how they interact in a portfolio; and
2. **Phase 3:** a final portfolio analysis, in which the focus is on a reduced select set of portfolios for further evaluation across a range of futures and sensitivities and more detailed reliability modeling in the process of identifying an MCEP.

This two-stage framework is illustrated in Figure 48. The framework of scenarios, futures, and sensitivities ensures that the choice of MCEP is robust in a variety of futures and mitigates risks explored in sensitivities.

Figure 48. Diagram of two-stage scenario analysis process used in PNM's 2023 IRP



5.1.1 Scenarios

Phases 1 and 2: Portfolio Screening Analysis

The scenarios studied in the first stage represent a large series of controlled experiments with several purposes: (1) to help develop, test, and validate the functionality needed to represent a wide range of technology options in the IRP modeling tools; (2) to study the role that different resources (or combinations of resources) could play in meeting mid- and long-term needs; and (3) to inform the design and definition of a final set of scenarios for analysis in Phase 3 based on the most promising results observed in this screening stage. The full list of scenarios studied in the first stage is provided Table 25, which includes brief descriptions of the key components of each scenario that distinguishes it from the others.

Table 25. Scenarios studied in Phases 1 and 2 of analysis

Scenario Name	Scenario-Specific Assumptions
Base technologies	Only solar, storage, and EE, DR allowed as options during planning horizon
LD storage - CAES	At least 100 MW of compressed air energy storage by 2032
LD storage - Flow	At least 100 MW of flow batteries by 2032
LD storage – IAS	At least 100 MW of iron air storage by 2032
LD storage - LAES	At least 100 MW of liquid air energy storage by 2032
LD storage - PHS 8-hr	300 MW of pumped storage (8hr) by 2032
LD storage - PHS 70-hr	300 MW of pumped storage (70hr) by 2032
LD storage - Thermal	At least 150 MW of thermal energy storage by 2032
Thermal – CT	New H_2-ready CTs allowed
Thermal - Linear	New hydrogen-ready linear generators allowed
Wind expansion	New wind & associated transmission allowed beginning in 2028
CCS - CCGT retrofit	Afton CC (235 MW) retrofitted with CCS capability
CCS - Net Power	280 MW NET power plant added by 2032
Green hydrogen	~250 MW H_2-fueled CT & ~750 MW electrolysis load added in 2031
PHS 70-hr + CT	300 MW of pumped storage (70-hr) by 2032; new H_2-ready CTs allowed
PHS 70-hr + CT + wind	300 MW of pumped storage (70-hr) by 2032; new H_2-ready CTs allowed; new wind beginning in 2028
PHS 70-hr + Linear gen.	300 MW of pumped storage (70-hr) by 2032; new H_2-ready linear generators allowed
PHS 70-hr + Afton CCS	300 MW of pumped storage (70-hr) by 2032; Afton CC (235 MW) retrofitted with CCS capability
PHS 8-hr + CT	300 MW of pumped storage (8-hr) by 2032; new H_2-ready CTs allowed
PHS 8-hr + CT + wind	300 MW of pumped storage (8-hr) by 2032; new H_2-ready CTs allowed; new wind beginning in 2028
PHS 8-hr + Linear gen.	300 MW of pumped storage (8-hr) by 2032; new hydrogen-ready linear generators allowed
PHS 8-hr + Afton CCS	300 MW of pumped storage (8-hr) by 2032; Afton CC (235 MW) retrofitted with CCS capability
IAS + CT	At least 100 MW of iron air storage by 2032; new H_2-ready CTs allowed
IAS + CT + wind	At least 100 MW of iron air storage by 2032; new H_2-ready CTs allowed; new wind beginning in 2028
IAS + Linear gen.	At least 100 MW of iron air storage by 2032; new hydrogen-ready linear generators allowed
IAS + Afton CCS	At least 100 MW of iron air storage by 2032; Afton CC (235 MW) retrofitted with CCS capability
Wind expansion + CAES	At least 100 MW of compressed air energy storage by 2032; new wind beginning in 2028
Wind expansion + BESS	New wind beginning in 2028; battery storage can be added in wind zone
IAS + LAES	At least 100 MW of iron air storage and at least 100 MW liquid air energy storage by 2032
Green hydrogen + wind	~250 MW H_2-fueled CT & ~750 MW electrolysis load added in 2031; new wind beginning in 2028
Flow + CT	At least 100 MW of flow batteries (10-hr) by 2032; new H_2-ready CTs allowed
Flow + CCS	At least 100 MW of flow batteries (10-hr) by 2032; Afton CC (235 MW) retrofitted with CCS capability
Base tech + LDES + CT	Base technologies, CTs (2026+), and any long-duration storage technology (2028-2033)
Base tech + LDES	Base technologies and any long-duration storage technology (2028-2033)

Phase 3: Final Portfolio Analysis

The list of the six final scenarios investigated in this IRP are shown in Table 26, along with brief descriptions of their assumptions and purposes. Additional detail behind the rationale for the definition and design of each of these scenarios is discussed in Section 7.3.1, following discussion of results of analysis from Phases 1 and 2.

Table 26. Scenarios considered in Phase 3 of analysis

ID	Name	Description & Rationale for Inclusion
1	Base Technologies Only	• Referent to 2020 IRP “No New Combustion” scenario
2	Base Technologies & Long-Duration Storage	• Requested by stakeholders
3	Base Technologies & Hydrogen Ready CTs	• Referent to 2020 IRP “Technology Neutral” scenario • Least cost scenario among Stage One scenarios reliant exclusively on mature technologies
4	Base Technologies, Hydrogen-Ready CTs, and Long Duration Storage	• Combination of Scenarios 2 and 3 • Created to understand if synergies exist across limited range of technologies
5	All Resource Options	• Combination of Scenarios 1 through 4 • Created to understand if synergies exist across greater range of technologies
6	Base Technologies & Hydrogen Electrolysis	• Variant upon 2020 IRP “Technology Neutral” scenario • Deep dive into implications of hydrogen-related tax credits in IRA for PNM customers (includes explicit representation of hydrogen electrolysis and storage)

The set of technologies considered in each scenario is the primary determinant of the differences among them; Table 27 shows the specific technology options considered in each of the different scenarios.

Table 27. Resource options considered across Phase 3 scenarios

Category	Resource	1	2	3	4	5	6
Demand-Side Resources	Energy Efficiency	✓	✓	✓	✓	✓	✓
	Demand Response	✓	✓	✓	✓	✓	✓
Renewable Resources	Solar PV	✓	✓	✓	✓	✓	✓
	Wind	✓	✓	✓	✓	✓	✓
Storage Resources	Lithium-Ion	✓	✓	✓	✓	✓	✓
	Flow	-	✓	-	✓	✓	-
	Pumped Hydro	-	✓	-	✓	✓	-
	Compressed Air	-	✓	-	✓	✓	-
	Liquid Air	-	✓	-	✓	✓	-
	Thermal	-	✓	-	✓	✓	-
	Iron-Air	-	✓	-	✓	✓	-
	H_2 Electrolysis	-	-	-	-	-	✓
Thermal Resources	H_2-Ready CTs	-	-	✓	✓	✓	✓
	Linear Generator	-	-	✓	✓	✓	-
	CCS Retrofit	-	-	-	-	✓	-

Stakeholder-Requested Scenarios

In the facilitated stakeholder process, stakeholders were asked to provide feedback on the design of scenarios for PNM's IRP analysis; many of the scenarios described above were informed directly by those comments. In addition, stakeholders were invited to submit requests for additional scenarios to model using the IRP tools. This resulted in an additional seven scenarios for analysis in the IRP; the details of those scenarios are presented in Table 28 and results are included in Appendix J.

Table 28. Scenarios requested by stakeholders

ID	Description	Description
1	2035 CO2-free	Requires PNM to eliminate all carbon emissions by 2035 rather than 2040
2	High EV & Building Electrification	Combines High EV & High Building Electrification load forecasts
3	FCPP Retires 2031 & Valencia PPA Extended	Analyzes various permutations of (1) early FCPP exit, (2) extension of Valencia PPA, and (3) extension of Reeves beyond its depreciable life
4	FCPP Retires 2031 & Valencia/Reeves Extended	
5	FCPP Retires 2027 & Valencia PPA Extended	
6	FCPP Retires 2027 & Valencia/Reeves Extended	
7	Increased Demand Response	Tests impact of hypothetical incremental demand response on portfolio (no costs for DR included)

5.1.2 Futures

A **future** consists of a set of forecasts and projections that describe the state of the world. The different forecast components that define a future can be found in the first column of Table 29. These range from customer-related factors including load forecast and adoption of end use electrification to broader factors such as the prices of gas, electricity, CO2, and technology capital costs.

Generally, PNM has little to no ability to influence which future becomes reality. The **"Current Trends & Policy"** future reflects the best estimates of the future state of the world based on the knowledge at the time of the IRP's development. Specifically, in this future, PNM assumes:

- Continued economic and population growth within PNM's service territory consistent with trends as forecast by Woods and Poole, as well as modest levels of incremental customer solar and electrification;
- Future commodity pricing assumptions based on projections provided by PACE Global that are intended to represent a most likely outcome in gas and electric markets;
- Technology pricing and future technology cost declines developed based on recent bids provided to PNM and NREL's latest 2022 Annual Technologies Baseline (ATB); and
- Federal tax credits established by the Inflation Reduction Act available throughout the duration of the planning period (with the exception of the 45V tax credit for hydrogen production, which is assumed to expire after 2032 as currently legislated).

Alternative futures take plausible forecast combinations that could be the result of deviations from assumed economic growth or more aggressive climate-based regulation. In a future with stronger emphasis on environmental impacts, the costs of renewable resources and battery storage would become more critical.

Table 29. Definitions of futures based on key assumptions

Assumption	Current Trends & Policy	High Economic Growth	Low Economic Growth	National Climate Policy
Load Forecast	Mid	**High**	**Low**	Mid
BTM Solar Forecast	Mid	**High**	**Low**	**High**
EV Adoption Forecast	Mid	**High**	**Low**	**High**
Building Electrification Forecast	None	None	None	**High**
Economic Development Forecast	Limited	**Stable**	Limited	**Stable**
Gas Price Forecast	Mid	Mid	**Low**	**High**
Carbon Price Forecast	Mid	Mid	Mid	**High**
Technology Cost Forecast	Mid	Mid	Mid	**Low**

The **"High Economic Growth"** future reflects an alternative assumption of more aggressive future growth of the New Mexico economy. In addition to driving an increase in the growth of electric demands, this future assumes that rapid economic growth also leads to greater levels of customer adoption of solar resources and electric vehicles. In combination, these factors increase demand while reshaping its daily patterns.

The **"Low Economic Growth"** future assumes a persistent lower level of growth in the New Mexico economy. In contrast to the High Economic Growth future, lower levels of growth are assumed to reduce customer adoption of solar and electric vehicles. In addition, this future assumes that a lower growth environment would indicate sustained low natural gas prices through the horizon of the analysis.

The **"National Climate Policy"** future represents a plausible future set of conditions that reflective of increased state and federal commitments towards environmental regulation. This future is intended to represent a level of policy ambition above and beyond current legislation (including the recently passed Inflation Reduction Act), which are already captured under the Current Trends & Policy future. This future incorporates several additional adjustments:

- Through its commitment to the Paris Agreement, the state of New Mexico has already signaled the priority of achieving deep economy-wide reductions. Numerous studies of economy-wide reductions, including analyses specific to the state of New Mexico, indicate that electrification is a key pillar of meeting such aggressive goals. While specific policies do not yet exist in New Mexico to drive such aggressive levels of electrification, this future presumes increases in load due to accelerated electrification of both vehicles and buildings.
- With respect to commodity pricing, this future incorporates a higher natural gas price forecast intended to capture the plausibility that future restrictions on natural gas fracking

could restrict production and lead to upward pressure upon the prices in today's competitive markets. This future also includes a high carbon price forecast, reflecting the eventual possibility of regional or national carbon pricing schemes.

- Finally, this future assumes aggressive technology cost declines for wind, solar, and battery storage. The rationale for this assumption is that under aggressive environmental regulation, a combination of policy-driven decisions – increased R&D spending, extensions of tax credits, accelerated learning due to deployment of technology on a larger scale – could drive cost reductions at rates beyond the level assumed in the "Current Trends & Policy" future.

5.1.3 Sensitivities

A **"sensitivity"** is an analysis of the impact of varying a single input assumption within a defined scenario or future. The adjustment of a single assumption isolates the impact of critical uncertainties or decision points to identify the key risk factors to the portfolio, quantifying their impact on the expected cost as well as how they affect the types of resources identified in the plan. Table 30 lists the variables examined in the sensitivity analysis and the default assumptions for each under the Current Trends & Policy Future.

Table 30. Sensitivities modeled in the 2023 IRP

Category	Sensitivity	Notes
Load Forecast	High EV	Identifies incremental resource needs to meet accelerated adoption of electric vehicles
	Stable ED	Stress-tests scalability of different strategies under an upper bound trajectory for future economic development loads
	TOU	Quantifies the potential value of load reductions enabled by changes in TOU pricing offerings
Technology Costs	High Technology Costs	Quantifies impacts of higher and lower future cost trajectories for solar, wind, and energy storage upon resource selection and cost
	Low Technology Costs	
Commodity Prices	High Gas Prices	Quantifies impacts of higher and lower future prices for natural gas upon resource selection and cost
	Low Gas Prices	
	$0/ton CO2 Price	Examines impacts of a range of carbon prices as required by Commission pursuant to final order in Case No. 06-00448-UT
	$8/ton CO2 Price	
	$20/ton CO2 Price	
	$40/ton CO2 Price	
Miscellaneous	FCPP 2027 Exit	Analyzes the impacts of an earlier exit from FCPP than the base assumption (2031)
	DERMS	Represented by additional BTM solar and storage
	10-yr Tax Credit Exp.	Explores impacts of a sooner expiration date for IRA tax credits

5.2 Modeling Methodology

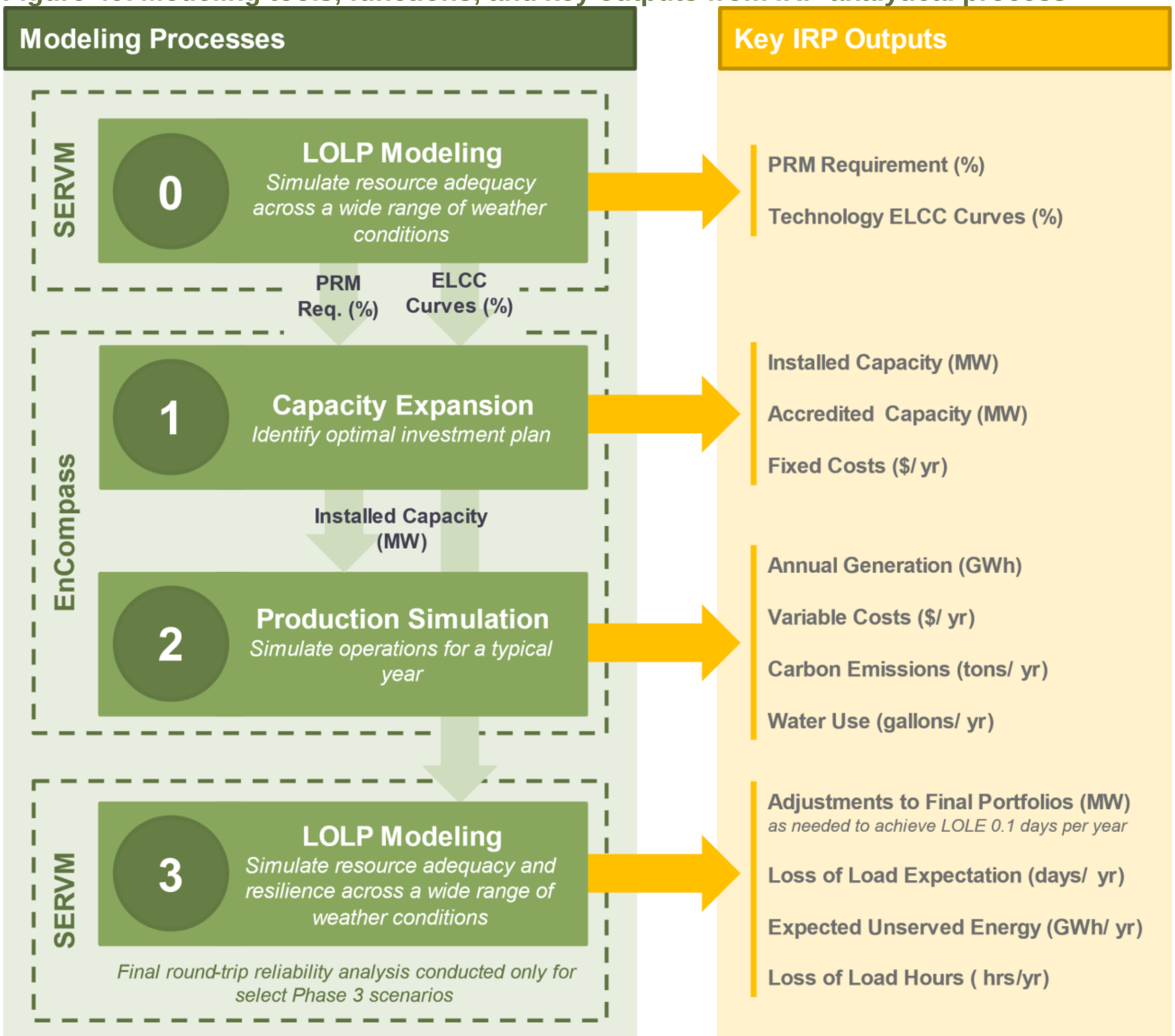
In this cycle, PNM continues to use industry-leading modeling software as the foundation for resource planning analysis. The modeling toolkit relies primarily on two complementary commercial modeling tools:

1. **EnCompass**, an optimal capacity expansion and production simulation model created by Anchor Power Solutions, which is used to identify and simulate portfolios least-cost resources to meet future needs; and

2. **SERVM**, a loss-of-load probability model developed by Astrapé Consulting, which is used to establish system reliability needs and to conduct detailed reliability analysis of portfolios produced by EnCompass.

Both of these tools are necessary to obtain a robust result that balances the planning objectives. To produce optimized portfolios, EnCompass incorporates a representation of how the system will operate across a sampling of representative days over the course of the study horizon; however, due to the computational complexity of the optimization problem, it is not practical to include direct simulation of all possible conditions within the optimization itself. At the same time, PNM's reliability standards dictate that the portfolio should yield no more than one day of lost load in ten years; accurately characterizing whether a portfolio meets that standard and the extent to which different types of resources can contribute to it requires a tool that can quickly simulate *thousands* of years' worth of conditions. By pairing these tools together, the IRP identifies and evaluates a range of portfolios that meet PNM's environmental goals and reliability standards. Using one without the other would jeopardize the ability to select long-term portfolios that are sufficient to meet load while also addressing factors of cost, environmental considerations and regulatory requirements.

Figure 49. Modeling tools, functions, and key outputs from IRP analytical process



5.2.1 Resource Adequacy Studies

Historical Context

Like most utilities, PNM utilizes a planning reserve margin requirement, which specifies the amount of capacity needed in the portfolio relative to expected peak demand, to ensure compliance with a desired reliability standard. Over time, the accounting conventions used in this framework have been refined and improved to ensure alignment with industry best practices for resource adequacy planning.

- Prior to the 2017 IRP, PNM used a planning reserve margin requirement of 13% to ensure the portfolio had sufficient resources to meet customers' needs based on a stipulation approved in NMPRC Case No. 08-00305-UT. At the time, this approach provided a simple and intuitive way to ensure the portfolio's resource adequacy: by focusing on the resources needed to meet peak demand—plus some margin to account for potential extreme weather, unit outages, and operating reserve needs—PNM met reliability needs with a portfolio comprising mostly nuclear, coal, and gas.

- Beginning in the 2017 IRP, recognizing that the traditional peak-hour planning approach was increasingly untenable with the expected additions of intermittent renewable resources, PNM adopted new tools and methods to support more advanced resource adequacy analytics. With the support of Astrapé Consulting, the 2017 IRP used SERVM, a loss-of-load-probability model,[23] to conduct Monte Carlo simulations of portfolios across a broad range of conditions. This was a pivotal shift that allowed for evaluation of the resource adequacy of supply across all hours of the year. The analysis in the 2017 IRP led to the notable conclusion that the previous 13% reserve margin requirement would not be sufficient maintain the desired standard for reliability, a frequency-based standard of "two days in ten years."
- The 2020 IRP sought to integrate loss of load probability modeling into the planning framework more comprehensively. PNM used SERVM to calculate the PRM requirement for the system corresponding to an LOLE target of 0.2 days per year ("one day in five years"). Meeting this standard required a PRM of 18%, an increase from the previous 13% PRM requirement. PNM also used SERVM to calculate the effective load carrying capability (ELCC) for renewable and storage resources, a widely used method to account for the reliability contributions of variable and energy-limited resources in a consistent manner.

Current Approach

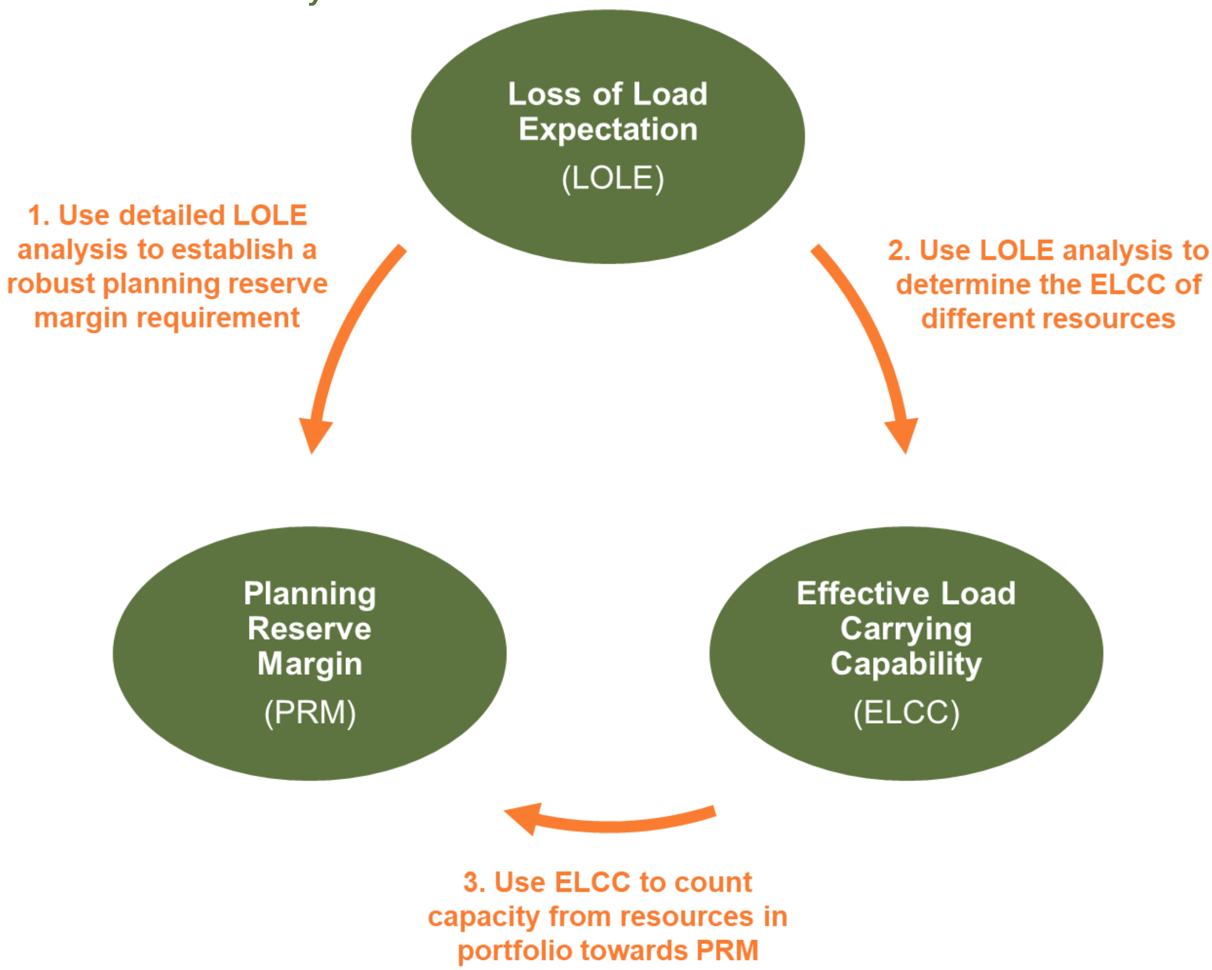
Since the 2020 IRP, PNM have continued to refine and improve the methods used to plan for resource adequacy. The current approach is engineered to ensure that the portfolio adheres to an industry-standard loss-of-load expectation of one day in ten years, which is achieved through careful calibration of a planning reserve margin and a capacity accreditation framework that continues to apply ELCC across a wide range of resources (including renewables, energy storage, and demand response). This analysis is conducted using the SERVM loss-of-load-probability model, which uses Monte Carlo and statistical techniques to simulate loads and resources across hundreds of years of conditions. This approach allows for analysis of resource needs across a broad range of conditions while considering extreme load events, renewable variability, unplanned outages, and other dispatch constraints. These analytical methods are foundational to a robust and durable framework for resource adequacy in a system with increased penetration of variable and energy-limited resources, shown below in Figure 50. Within this framework, the planning reserve margin is not the goal itself, but means to an end: a portfolio of resources that meets a "one day in ten years" standard for reliability.

Key Term

Effective load carrying capability (ELCC) *refers to a methodology used to measure the contribution of a specific type of generating resource towards system resource adequacy needs by comparing it against a common benchmark (often a "perfect capacity" resource available at full capacity at all times) in a loss-of-load-probability model.*

[23] 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.

Figure 50. Key elements of a robust resource adequacy framework that considers needs across all hours of the year



Key Elements and Enhancements in the 2023 IRP

As discussed in Section 2.2, planning for resource adequacy is increasing in complexity due to the increasing variability of both loads and resources. The 2023 IRP includes a number of refinements to the methods used in the 2020 IRP in an effort to maintain alignment with industry best practices and to capture the evolving nature of reliability challenges presented by a transition to a carbon-free system.

1. Adoption of the "One Day in Ten Years" standard

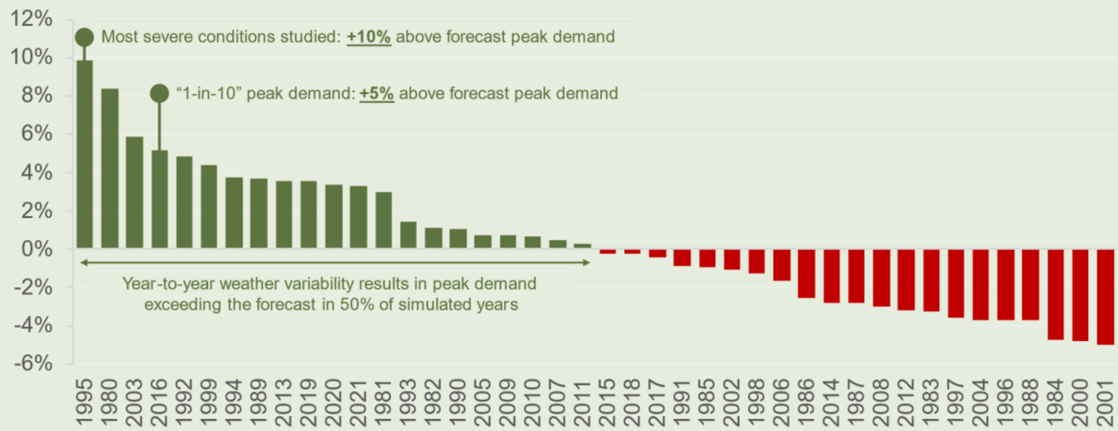
In the 2020 IRP, PNM highlighted its intent to transition from an LOLE standard of 0.2 days per year to the more common industry standard of 0.1 days per year in future IRPs. The 0.2 days per year standard was chosen as the planning target in the 2020 analysis to balance historical continuity with technical analysis using LOLP modeling. While there is no formal reliability standard in the industry, most utilities using currently use a standard of 0.1 days per year. This adjustment is necessary to adhere to best practices and to serve customers' needs in a more reliable manner in an era of uncertainty and rapid transformation.

While LOLE is used as the primary reliability metric for planning in this IRP, loss of load probability models can also be used to evaluate other reliability metrics. These include metrics like Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE), which provide information on the duration and magnitude of unserved energy events. As the penetrations of variable and energy-limited resources increase, focusing on only the frequency of loss of load events may not be sufficient to maintain a standard of reliable services of the best quality for customers. PNM intends to continue to monitor the changes in the system and the broader market and will evaluate the benefits of introducing standards related to additional reliability metrics in the future.

Stakeholder Input: Analyzing Reliability in Extreme Weather Conditions

Over the course of the facilitated stakeholder process, multiple stakeholders raised questions regarding how PNM's planning processes would consider the reliability needs associated with extreme weather events. The use of loss-of-load-probability modeling as a core part of the IRP ensures that the portfolio is designed to meet the LOLE standard of 0.1 days per year while accounting for the probability that extreme weather events could cause electricity demand above PNM's forecast. The figure below shows the distribution of peak load conditions simulated in SERVM to represent this range of potential outcomes across a range of weather years spanning from 1980 to 2021. Across this sample, the "1-in-10" peak demand (the fourth highest value across a sample of approximately 40 years) is 5% above forecast peak, and the most severe weather conditions modeled results in demand 10% above forecast peak. These conditions are represented probabilistically in all simulations to ensure that portfolios adequately meet reliability needs under both typical and extreme weather conditions.

Peak Demand in Each Weather Year Relative to Forecast
(%)



2. Improved representation of "interactive effects" in ELCC accounting

In the 2020 IRP, SERVM was used to calculate ELCC curves for renewables and storage resources to account for the reliability of these resources in an appropriate manner, recognizing the limitations inherent in these technologies. Use of ELCC has quickly become the consensus best practice within the industry: it has been adopted by numerous other utilities throughout the

West, as well as in regional resource adequacy programs and organized capacity markets.[24] The application of ELCC to count renewables and storage is a cornerstone of a robust resource adequacy accounting framework that can account for resource needs across all hours of the year.

A resource's ELCC is defined as the amount of "perfect capacity" that provides the same contribution to a utility's resource adequacy needs; that is, a 100 MW resource with a 50% ELCC has an identical impact on system reliability as a 50 MW resource that is available at full capacity at all times throughout the year. The derivation of ELCC from the fundamentals of loss-of-load-probability modeling allows it to capture several dynamics crucial to maintaining resource adequacy with high levels of renewables and storage:

1. Any specific non-firm technology generally exhibits a declining marginal ELCC with increasing penetration. The most obvious example of this phenomenon is the decreasing capacity value of solar: while the first increment of solar added to a summer-peaking system is relatively coincident with the demand profile, increased levels of solar will cause the net peak to shift into the evening, when additional solar provides limited to no incremental capacity value. While solar provides the most obvious example of this phenomenon, this is generally true of all non-firm resources to some extent.

2. Multiple technologies can produce total ELCCs that are greater than (or less than) the sum of their individual parts. This phenomenon, often described as a "diversity benefit" when positive, can be attributed to interactive effects between specific technologies. Solar and storage are one common example of a resource combination that produces diversity benefits.

While the ELCC analysis in the 2020 IRP included a robust treatment of the first effect above (declining capacity value for individual technologies), it was limited in its treatment of the interactive effects between *new* resources (interactive effects between complementary technologies). EnCompass was not able to handle a multidimensional set of ELCC curves that would be needed to fully capture these types of interactive effects; as a result, ELCC curves were modeled for each technology independently. Stakeholders criticized this approach as failing to account for important dynamics that would shape the reliability needs of the 2040 portfolio.

While the functionality in EnCompass has not been updated to allow for full accounting of interactive effects, the 2023 IRP incorporates a modeling approach for ELCC curves designed to remedy some of the critiques posed by stakeholders. It does so by adjusting the technology-specific ELCC curves over time to account for *assumed* changes to other types of resources in the portfolio. This solution is also imperfect and requires iterative calibration but leads to more satisfactory outcomes by capturing the combined capacity value of renewables and energy storage. Details on the specific ELCC curves applied to these resources are provided in Section 7.1.3.

[24] Utilities and regulators that currently rely upon ELCC for capacity accreditation in the West include: Arizona Public Service, California Public Utilities Commission, El Paso Electric, Northwestern Energy, NV Energy, Portland General Electric, Puget Sound Energy, Sacramento Municipal Utilities District, Salt River Project, Tucson Electric Power, and Xcel Energy. Additionally, WRAP has indicated its intent to use ELCC methodologies for capacity accreditation.

Stakeholder Input: Capturing ELCC Interactive Effects

One of the criticisms that stakeholders offered of the 2020 IRP was that the methodology used to characterize ELCCs for wind, solar, and storage did not fully account for interactive effects between those technologies. Stakeholders argued that the use of one-dimensional ELCC curves that do not adjust over time could lead to an understatement of the capacity value of renewables and storage resources. In written comments, one stakeholder noted "…it is critical for PNM's modeling and resource selection strategy to account for the capacity value diversity benefits among wind, solar, and storage."[25] Multiple stakeholders participating in the 2023 IRP processes expressed the same concern. The improvements described above – whereby ELCC curves are adjusted at select points in the analysis to reflect the changing penetrations of other resources in the portfolio – represent an important step forward in the ability to capture those interactive effects in modeling. Further, the use of round-trip modeling described in Section **5.2.4** to test and adjust the final portfolios in Phase 3 ensures that the IRP analysis properly accounts for interactive effects among different technologies in the portfolio in both the near and long term.

3. Continued use of UCAP accounting conventions for thermal resources

As part of PNM's effort to strengthen its resource adequacy planning conventions, the 2020 IRP also adjusted the accounting conventions used to count thermal resources towards the PRM requirement: instead of counting the full nameplate capacity of each thermal unit towards the requirement, its contribution is derated according to its expected forced outage rate to calculate its "unforced capacity" (UCAP). This approach allowed for a more consistent treatment of thermal, renewables, and storage resources, providing for a more stable reserve margin that is less sensitive to changes in the resource portfolio. This accounting change commensurately impacts the contributions of the individual thermal resources as well as the requirement itself;[26] that is, relative to the previous approach, it has no impact on the quantity of new resources needed to achieve a certain LOLE standard.

4. Updates to neighboring market assumptions

SERVM is configured to include a representation of neighboring markets to the PNM Balancing Authority (BA). The availability of imports from neighboring markets impacts PNM's reliability needs in two ways:

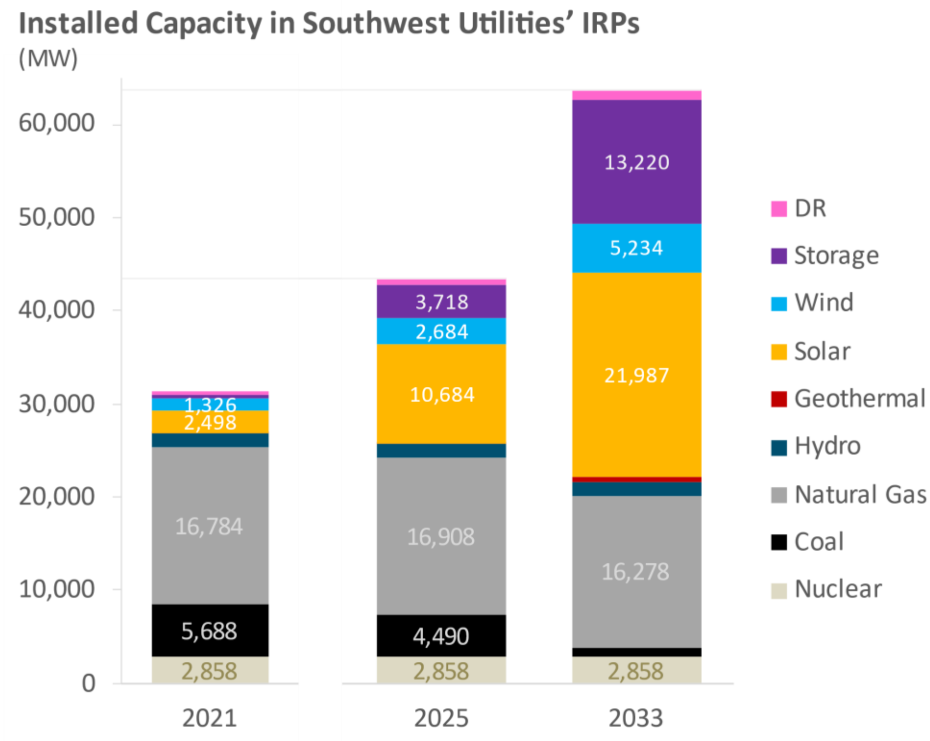
1. The availability of imports in the wholesale market, a result of the load and resource diversity among utilities in the region, allows PNM to carry a lower PRM requirement that would be necessary if PNM were an electrical island (this dynamic was discussed extensively in the 2020 IRP).
2. The hour-to-hour profile of import availability has implications on the capacity value of future resources; for example, in a market saturated with solar generation in the daytime, the capacity value of solar on the PNM system may be reduced.

[25] Comments of Interwest Energy Alliance

[26] In other words, the adoption of the UCAP convention will allow PNM to maintain a PRM requirement that is more consistent with the capabilities of the units than if PNM had maintained the convention of counting thermal resources at their installed capacity.

The representation of neighboring systems used in the 2020 IRP represented a relatively contemporaneous view of loads and resources in those areas based largely on the conditions in the existing systems at the time: the assumptions reflected existing loads and resources, adjusted only to capture specific announced additions and retirements. However, neighboring systems are also experiencing rapid changes in loads and resources, and many IRPs among regional utilities indicate plans to develop large quantities of renewables and energy storage resources. Capturing how those changes to those neighboring markets would impact regional loads and resources is necessary to capture how availability of imports will vary based on season and time of day. These expected changes were compiled in E3's study *Resource Adequacy in the Desert Southwest* (see Figure 51), which was in turn used as the basis for development of assumptions of future loads and resources in this IRP.

Figure 51. Projected changes in regional resource mix among utilities serving the states of Arizona and New Mexico[27]



Reflects resources dedicated to serving loads of utilities in Arizona and New Mexico; data current as of 2021

In addition to this update, the resource adequacy analysis maintains a limit on the level of "market assistance" (reflecting energy available for purchase in wholesale markets) during the summer net peak period that is informed by real-world operating experience. While PNM's ability to purchase energy from neighboring utilities allows it to carry a lower reserve margin than if it were an electrical island. However, the risk of overstating the availability of market assistance – that PNM customers could be subject to disruption of service due to conditions outside of the PNM system – warrants careful consideration in the treatment of market assistance in planning.

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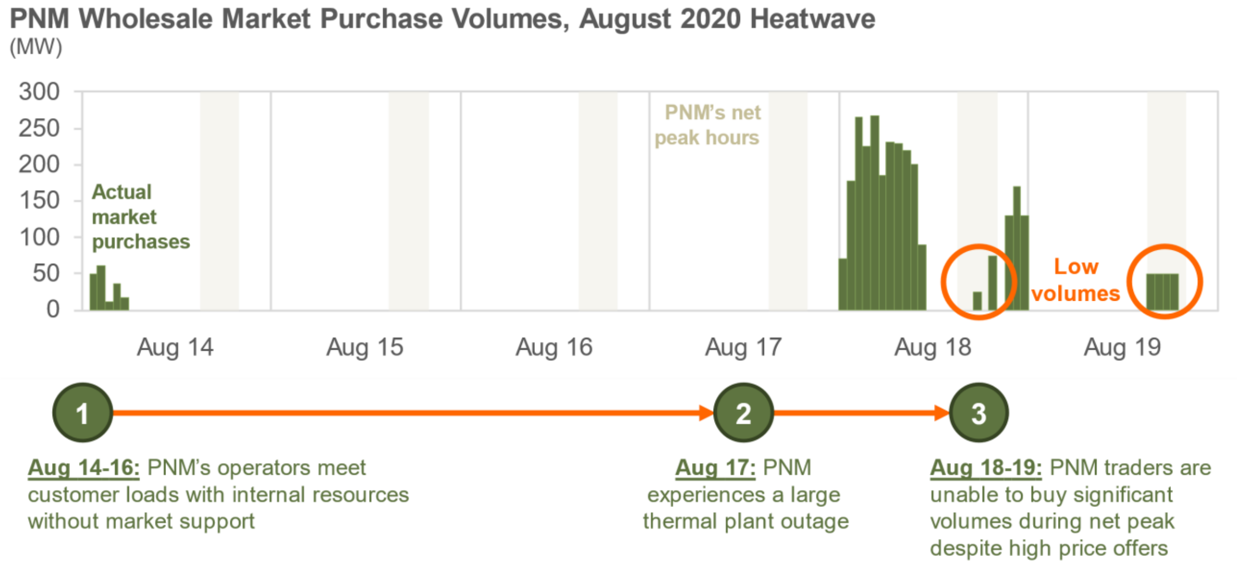
[27] Figure adapted from E3's *Resource Adequacy in the Desert Southwest*

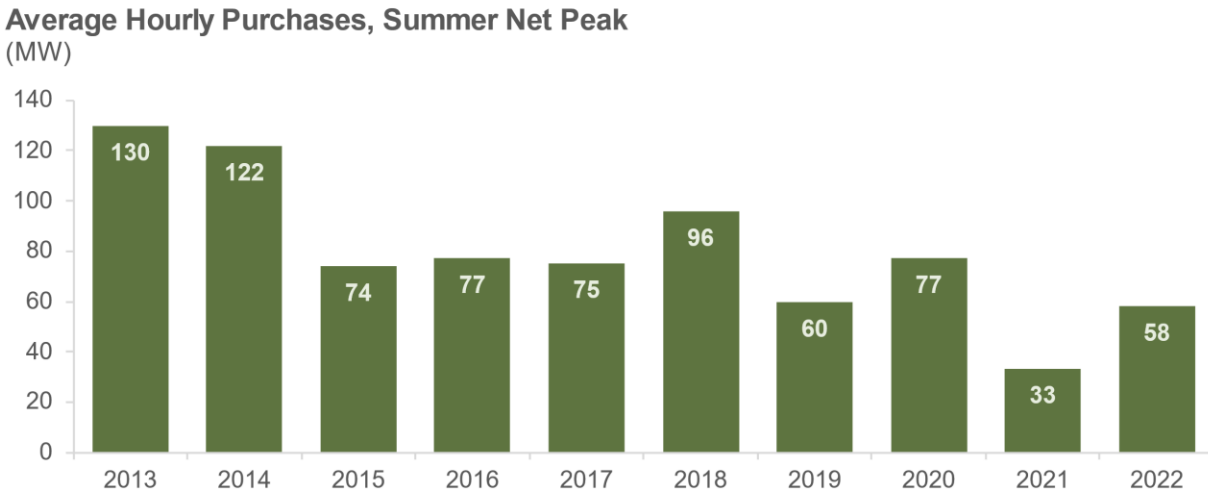
The 2020 IRP introduced a limit on market assistance of 50 MW during the net peak period. This was established to reflect a level of imports that PNM's planners and operators believed would be available if needed during that period with reasonably high confidence. This level was informed by historical events such as the west-wide heat wave of August 2020. During this event, in the days following an unplanned outage at a large thermal generator, PNM's traders were limited in their ability to purchase energy on the wholesale market during net peak periods despite offering very high prices. This series of events is shown visually in Figure 52.

Figure 52. PNM's market purchases during west-wide heatwave in August 2020



The fundamental dynamics that led to this series of events – namely, the shrinking reserve margins across the Western Interconnection discussed in Sections 2.3.1 and 2.3.2 – have persisted since the 2020 IRP. Figure 53 shows the trend in historical market purchases made by PNM during the summer net peak window (defined as spanning the hours 19-22 in the months of June through August), indicating that limited availability of wholesale energy during constrained periods continues to be a challenge. As a result, the resource adequacy studies in this IRP maintain a limit of 50 MW of market assistance during the net peak periods.

Figure 53. Historical market purchases by PNM during net peak periods

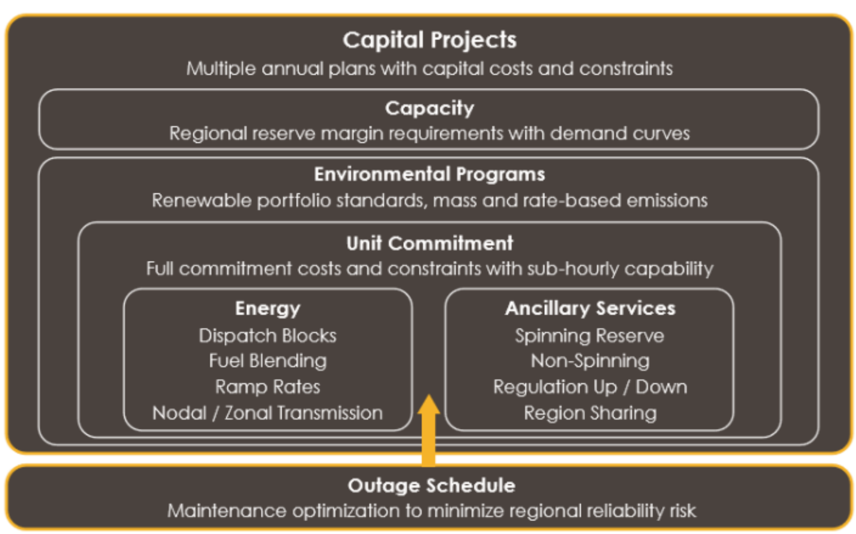


5.2.2 Capacity Expansion

EnCompass, developed and maintained by Anchor Power Solutions, is an optimal capacity expansion and production simulation model designed for long-term integrated resource planning. In the IRP, PNM uses EnCompass for two functions:

- **Long-Term capacity expansion (LTCE):** EnCompass produces least-cost portfolios of resources to meet future needs, subject to resources operating parameters, constraints on reliability, and the various environmental and regulatory requirements established by the planning processes; and
- **Production simulation:** EnCompass simulates the hourly operations—and the associated cost of serving loads—of each portfolio across the full planning horizon, capturing detailed unit commitment dynamics, dispatch constraints, and transmission limitations of the system.

Figure 54. Illustration of EnCompass modeling framework (courtesy Anchor Power Solutions)



For the 2023 IRP planning process, EnCompass' capacity expansion module is configured to identify least-cost portfolios of resources between 2023 through 2042 while meeting a number of constraints. The model's **"objective function"** – the sum of all costs included in the optimization – reflects the net present value of PNM's revenue requirement, including all costs related to the generation portfolio (existing and new resources) and new transmission investments needed to deliver future resources to loads. EnCompass minimizes this objective function subject to **"constraints"** – certain requirements that the portfolio must meet in order to be qualify as a valid solution, such as the PRM requirement and CO2 emission targets discussed later in this section.

EnCompass' modeling functionality is foundational to PNM's ability to identify a robust plan. Several of the most important features of EnCompass used to develop the plan are described below.

Endogenous Hourly Dispatch

Within the context of the capacity expansion optimization, EnCompass includes a representation of the hourly system dispatch of the portfolio to meet loads. As the capacity mix shifts towards renewable and energy storage resources, hourly system dispatch provides dynamic operational decisions expected in future system operations. Unlike dispatchable thermal generation that can be brought online as needed to match energy demand, generation from renewable resources is subject to availability limitations. For example, solar resources can generate power only during the day and wind speed varies by location, time of day and season. In Encompass, renewable resources are represented using hourly profiles which capture the temporal variation in renewable generation required for hourly system dispatch. Operation of energy storage resources, such as daily charging and discharging patterns, are also better represented using hourly system dispatch.

Dynamic ELCC Curves

Another key feature of Encompass for analysis is the capability to represent ELCC curves for each technology dynamically; that is, given an ELCC curve for a specific technology, Encompass can track how the marginal ELCC of that resource changes as the magnitude of that technology scales with the portfolio. This enables the modeling to account for saturation effects inherent to resources like solar and storage and is key to PNM's ability to optimize a portfolio while meeting resource adequacy needs.

Emissions Constraints

EnCompass optimizes a portfolio of resources according to constraints on carbon emissions (or emissions intensity), a key feature needed to ensure compliance with the future requirements of the ETA.[28] Yearly emissions intensity constraints are applied in all scenarios.

According to the requirements set forth by the ETA:

[28] EnCompass is also configured to ensure compliance with the RPS requirements of the ETA, but these constraints generally do not drive portfolio decisions due to the significant level of renewables included in the existing portfolio and the more stringent carbon constraints imposed in the modeling. Nonetheless, all portfolios are also designed to meet year-by-year RPS requirements.

> …the qualifying utility's generation and sources of energy procured pursuant to power purchase agreements **with a term of twenty-four months or longer**, and that are dedicated to serve the qualifying utility's retail customers, shall not emit, on average, more than four hundred pounds of carbon dioxide per megawatt-hour by January 1, 2023, and not more than two hundred pounds of carbon dioxide per megawatt-hour by January 1, 2032 and thereafter.
>
> – ETA Section 10D (emphasis added)

Initially, EnCompass was configured to impose constraints reflecting the ETA emissions intensity limits on all years analyzed. With the existing resource mix – which has been impacted by project delays – and without the capability to add incremental clean energy resources in addition to those already under development, the model produced infeasible expansion plans in the optimizations. The constraints for 2023 and 2024 were subsequently removed from the modeling, resulting in emissions intensity slightly above the 400 lbs/MWh requirement in those years. The constraints corresponding to the ETA's carbon intensity limits are imposed on all years after 2024. These levels of carbon intensity represent dramatic reductions in near-term and long-term carbon footprint from historical levels and will be achieved through both the elimination of coal generation in the portfolio and continued development of renewable and demand-side resources.

To capture these requirements in the modeling, the constraint is specified based on the total carbon emissions from PNM generation divided by PNM's retail sales (grossed up for losses). This is a conservative interpretation of the ETA requirements for two reasons. First, the ETA requirement divides carbon emissions by total generation, which is typically larger than retail sales due to off-system sales and energy losses from storage charge/discharge inefficiency. Second, the IRP imposes this constraint on an annual basis, whereas the ETA calls for measurement and verification of average compliance every three years.

Under this accounting regime, short-term wholesale market transactions are not directly considered in determining PNM's carbon intensity. To design portfolios that comply with the spirit and requirements of the ETA and do not rely excessively on short-term purchases, PNM does not allow for market purchases or sales in the capacity expansion step of the analysis. This approach ensures that PNM's portfolio includes enough resources to serve its loads while also complying with the requirements of the ETA. A key element in the design of portfolios is that each is capable of meeting the objectives of the ETA as well as PNM 2040 decarbonization goal.

Because of these considerations, throughout this IRP, results for environmental metrics are based on model outputs from the capacity expansion analysis rather than the subsequent production cost analysis. Under the ETA, PNM is not required to attribute carbon emissions to short-term wholesale market purchases. Because wholesale market purchases are included in the production cost modeling, the resulting emissions attributed to PNM's portfolio may be understated depending on real-world conditions. By focusing on emissions outputs produced by the capacity expansion model, PNM ensures that the portfolios developed in the IRP are capable of meeting future requirements regardless of the availability of short-term wholesale market purchases, which is inherently uncertain.

Treatment of Transmission in Resource Planning

EnCompass includes functionality to co-optimize generation and transmission investments. In developing the analysis for the 2020 IRP, PNM tested this functionality, exploring the potential to represent transmission upgrades physically in the model as explicit choices. PNM spent months developing and testing this functionality, but ultimately could not conclusively demonstrate that the results from the model were both sufficient to maintain reliability and provide least cost outcomes for customers. Extremely long model runtimes compounded the challenge of implementing this functionality, and PNM ultimately used transmission cost adders to reflect the associated costs of transmission upgrades in developing the 2020 IRP.

For the 2023 IRP, PNM revisited this modeling methodology and solicited feedback from stakeholders in workshops on the pros and cons of using different approaches to representing transmission in capacity expansion using a zonal modeling tool (see box below). The minimal feedback received from stakeholders, coupled with a review of current practices used by neighboring utilities, informed PNM's choice to continue to use transmission cost adders in the 2023 IRP.

Using information on transmission impacts of new resources in the IRP is a goal that PNM has been pursuing for years, and PNM is continuing to develop accurate models to take advantage of new functionality. PNM has recently licensed a nodal version of EnCompass, which PNM Transmission intends to use for various planning purposes. PNM hopes to utilize this new tool to quantify congestion and better understand interconnection and transmission service for its system. PNM expects that insights gained from a nodal model will also prove useful to enhance resource planning and modeling in future IRPs, providing important information on system limitations, capabilities and costs/benefits in its existing zonal modeling framework.

Stakeholder Request: Better Understanding of Transmission Modeling

In the early stages of the stakeholder process for the 2023 IRP, stakeholders expressed an interest in better understanding the treatment of transmission in the development of this long-term resource plan. In response to this request, PNM hosted two workshops entirely focused on transmission. These workshops included multiple presentations from PNM's transmission planning group on topics relating to how the transmission system is planned and operated, a presentation from external consultants (E3) describing the models and methodologies used by other utilities in the Western Interconnection to capture transmission in the IRP process, and extensive questions and commentary from interested stakeholders. Through these workshops, PNM solicited stakeholder input regarding the tradeoffs between different approaches to representing transmission in the IRP but received limited feedback.

Explicit Modeling of Hydrogen Production, Storage, and Consumption

In the 2020 IRP, hydrogen-ready combustion turbines were featured prominently in the Technology Neutral scenario, helping to meet system reliability needs in 2040 in a carbon-free portfolio alongside a portfolio comprising nuclear, solar, wind, storage, and demand-side resources. To represent how those resources would operate, the analysis assumed that by 2040, delivered hydrogen fuel could be purchased at a fixed price and delivered to the plant, much like natural gas and other fuels are today. In other words, the upstream infrastructure needed to produce, store, and deliver hydrogen to the point of combustion was not included in the analysis but was assumed to be reflected in the price of the fuel.

Since that point in time, new functionality has been introduced to EnCompass that allows for the explicit modeling of hydrogen production and storage infrastructure through components that may be linked directly to the generator that consumes the fuel. In light of the tax credits for hydrogen production established by the IRA, the capability to represent these processes explicitly is an important innovation that will allow for PNM to assess potential opportunities to produce hydrogen.

In this IRP, hydrogen-fueled generation is studied in the scenario analysis using both approaches described above: in some scenarios, hydrogen fuel is modeled as a commodity with a fuel price forecast like natural gas (as in the 2020 IRP), while in others, the full cycle of production, storage, and consumption is captured explicitly in the analysis. The assumptions used to characterize hydrogen as a commodity are discussed in Section **6.6**, and the assumptions used to model the hydrogen production and storage infrastructure are provided in Section **6.3.8**.

Enhanced Modeling Long-Duration Storage

One of PNM's goals in developing this IRP has been to build the technical capabilities that will be necessary to plan for and evaluate a wide range of future emerging technologies – including the many options for long-duration storage currently in various stages of development and commercialization. Because the dispatch of these resources can be influenced by patterns of supply and demand over timespans of hours, days, weeks, or even seasons, capturing their behavior is both complex and essential to understanding their future role in the portfolio. Many of the scenarios modeled in Phases 1 and 2 were designed specifically to test and refine EnCompass' ability to handle a wide range of resource characteristics appropriately. Ultimately, these efforts have represented an important step forward in PNM's ability to incorporate a wide range of options into its planning process, and PNM will continue to build upon this innovative functionality in future planning.

5.2.3 Production Simulation

While the capacity expansion run approximates system operations based on a sample of conditions – and associated metrics including energy mix, carbon emissions, and operating costs – the hourly analysis provides a richer view of the system's operations over the course of the year. Some differences in the representation of operations between the limited sample in the capacity expansion model and the full production simulation run due to the broader set of conditions studied. In addition, the production simulation runs allow for interactions with neighboring wholesale markets to reflect opportunities to reduce customer costs with short-term market purchases and sales. Under the ETA's rules, short-term market purchases do not count towards PNM's carbon intensity, and so in circumstances where the production simulation model chooses to buy from the market instead of dispatching PNM's own natural gas resources, the apparent emissions intensity of PNM's portfolio may appear lower than in the capacity expansion model runs.

Each day, PNM is responsible for reliably balancing loads and resources in real time. PNM's operators follow steps to ensure reliability consistent with the requirements of the NERC reliability standards. First, PNM develops a unit commitment plan to fully supply that day's projected hourly loads. The first step is to commit (i.e., schedule) all "must-take" (non-dispatchable) resources, which include nuclear, wind, solar, and geothermal, as well as the minimum output of any generation unit that is expected to be needed that day, including any "must-run" resources needed for reliability and transmission system reliability in accordance with contingency planning requirements. PNM then schedules all other generation using economic dispatch principles. This generally means the lowest cost generation unit being the first dispatched. Once projected hourly load is met, PNM commits additional generation needed to meet all operating reserve requirements that will ensure readiness for uncertainties and contingencies.

Operating Reserves

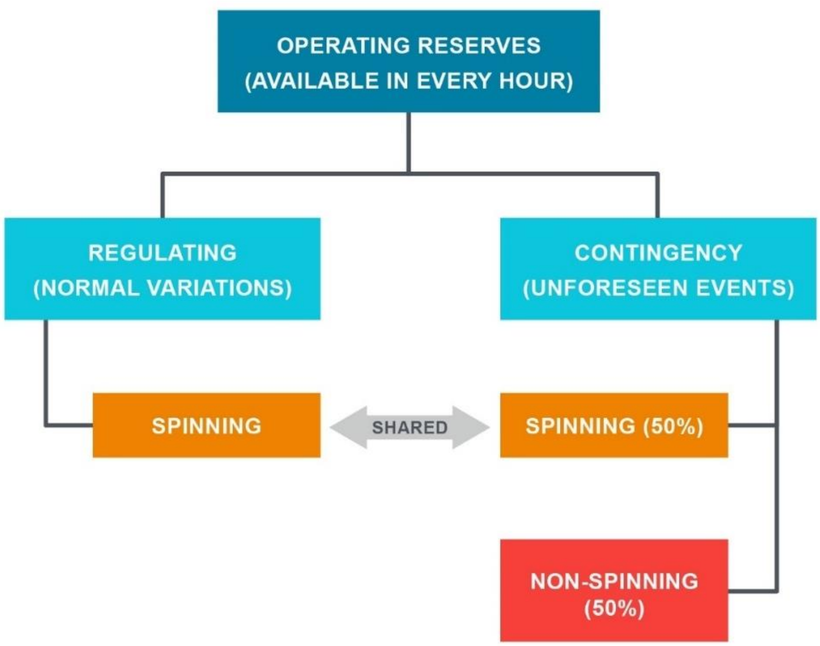
The term "operating reserves" refers to generating capacity that is used by the Balancing Authority (BA) system operator to respond quickly to disruptions or perturbations in demand or supply – for example, when a variable energy resource ramps down or a generator goes offline. To comply with NERC and WECC reliability criteria, PNM carries the following reserves:

- **Contingency reserves**, which allow the system operator to respond to unexpected events (e.g. generation or transmission outages); and
- **Regulation reserves**, which are used to respond to variations in load and renewable output on a second-to-second basis.

As mandated by NERC, the PNM BA carries contingency reserves equal the greater of: (1) 3% of the BA's load plus 3% of its online generation, or (2) the single largest contingency on the PNM system. Since 2022, the single largest contingency on the PNM system is the Afton Combined Cycle (235 MW) power plant. Historically, the now-retired San Juan Unit 4 (392 MW) was PNM's single largest contingency. In the future, as the composition of portfolio changes, the single largest contingency may be determined by different elements in the system.

The contingency reserve requirement can be further decomposed into "spinning" and "non-spinning" reserves. "Spinning reserves" are resources that are synchronized to the grid and can respond instantaneously; "non-spinning reserves" are not synchronized but can be brought online within a ten-minute period. Figure 55 illustrates the different types of operating reserves.

Figure 55. Operating reserves used by PNM to maintain day-to-day reliability



PNM meets a portion of these requirements through voluntary participation in the Southwest Reserve Sharing Group (SRSG), a group that includes fifteen utilities in the southwestern United States. The SRSG provides opportunities for cost savings to member utilities through more efficient dispatch by enabling a sharing of contingency reserves.[29] The actual level of shared

[29] This allows the members of the SRSG to share the single largest hazard requirement within the SRSG proportionally rather than having to carry reserves for individual single largest hazards of the respective BAs. For example, PNM's share of a full Palo Verde Unit 2 ~1340 MW hazard results in lower reserve

reserves available will vary depending on what loads and resources from SRSG members are committed at the time and what unit within the PNM BAA is forced out of service that requires assistance from SRSG. So, while the table below presents some indicative amounts of capacity that PNM could receive, these levels are just an example. Additionally, PNM is only able to receive assistance from the SRSG for at most one hour and within that hour the PNM BA must restore balance to the PNM BAA system as well as restore its reserves including its required contribution to the SRSG.

Table 31 summarizes PNM's largest hazards; how much assistance it can expect from its reserve sharing group (though as discussed above, actual values will vary), the Southwest Reserve Sharing Group (SRSG); and how much capacity is required to be available within 15 and 60 minutes.

Table 31. Inputs to Operating Reserves Requirements at Time of Summer Peak

Site of Single Largest Hazard	Size of Hazard (MW)	SRSG Assistance	15-Minute Requirement	60-Minute Requirement
Afton	235	160	70	25

Regulating reserves represent an incremental amount of reserve above this, sufficient to follow load and respond to fluctuations in the output of generating units, primarily 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[30]. PNM currently estimates that 13.8 MW of fast frequency response is needed to maintain compliance with the standard.

Sub-hourly Flexibility Needs & the Western EIM

In addition to the operating reserves that PNM holds to comply with NERC and WECC operating standards, PNM's participation in the EIM requires operators to meet flexibility reserve requirements when establishing day-ahead schedules for generation dispatch. These reserves are designed to ensure that the portfolio will have sufficient flexibility to respond to load and renewable forecast error and sub-hourly variability; a daily showing of sufficient flexibility reserves is a prerequisite to participation in the EIM.

PNM's flexibility reserve requirements are reviewed prior to each operating hour by CAISO. These requirements are based on CAISO's load forecasts, forecasts of variable energy resources and an assessment of the PNM BA area to meet forecast uncertainty/variability and resource diversity associated with the broad geographic footprint covered by the EIM.

Overgeneration and Renewable Curtailment

With significant amounts of new solar resources anticipated in the next few years, PNM's operators will increasingly face challenges that arise due to overgeneration conditions. "Overgeneration" describes a condition when the available generation from inflexible and renewable resources exceeds customer needs.

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requirements than if PNM were to try to meet the single hazard alone. At minimum PNM still has to keep 5% of BA load or resources as reserve per that agreement. The SRSG arrangement results in PNM typically needing to carry a minimum of 40-120 MW of reserve at any given time which is equally split between spinning and non-spin.

[30] This standard and other relevant standards are described in Appendix D

The transition to higher levels of reliance on variable renewable resources will increase the frequency of these types of events. By 2024, the portfolio will include over 1,400 MW of solar generation, which, if producing at full capacity, may exceed daytime load during the spring. When combined with generation from wind resources and the baseload output of PVNGS, the amount of available energy during the daytime may significantly exceed customer needs.

In order to manage the system under such circumstances and ensure continued balance of supply and demand, PNM's traders and operators have several options for recourse:

- **Use surplus to charge storage resources.** The capability to store surplus renewables and discharge when needed represents a significant share of the anticipated value of future energy storage resources. The storage resources that are expected to be online by 2024 will allow PNM to store up to 600 MW of surplus renewables, provided that the storage resources are not already fully charged; additional investments in storage may expand this potential. However, battery resources' four-hour duration will not always match the overgeneration events which is why PNM will need to pursue increased duration storage facilities as more renewables are added to the system.

- **Look for opportunities to sell surplus in wholesale markets.** If a willing counterparty within the region presents itself, PNM may be able to reduce overgeneration through off-system sales. However, depending on the timing and conditions of surplus, these opportunities may be limited – development of solar resources across the region will often mean that the occurrence of overgeneration will be a regional issue, rather than a utility-specific one.

- **Curtail renewable resources.** If surplus generation can be neither sold nor stored, operators will curtail renewable resources to maintain reliability.

In the transition to a highly renewable, carbon emissions-free portfolio, some amount of curtailment will be inevitable as part of a least-cost reliable portfolio; especially as the costs of renewables decline, it will not make sense to invest in storage to mitigate all overgeneration. The analytical methodology used to develop PNM's plan is designed to consider the amount of curtailment along other economic tradeoffs. However, as PNM starts to experience higher levels of curtailment this will factor back into the price of new renewable contracts as the solar and wind developers are now calculating the potential for limited curtailments as part of their pricing offers.

As discussed through this document, additional investments in storage and transmission have many benefits, one of which would be to reduce the number of curtailments from renewable generators and optimize the efficient use of the system. However, prudent planning requires PNM to plan the system as a whole – to reasonably assure resource adequacy while balancing environmental impacts and customer costs. No decision in resource planning can be viewed or made without consideration of all factors.

5.2.4 Detailed Reliability Analysis

Additional detailed reliability analysis is conducted for select scenarios in Phase 3.[31] This additional analysis serves dual purposes:

[31] This roundtrip analysis is not conducted on all scenarios modeled because it is time- and resource-intensive. Roundtrip modeling efforts focus upon the scenarios ultimately will considered for the MCEP in Phase 3.

1) This analysis serves as a check to ensure portfolios are sufficiently close to the desired LOLE standard of 0.1 days per year. In circumstances where this is not true, this analysis is used to make tune-up adjustments to the portfolios to bring them into line with this standard.
2) Simulating the portfolios in SERVM provides an expansive amount of additional information that helps to understand the nature of reliability risks in each of the portfolios. While all portfolios are designed to achieve a specific LOLE standard, portfolios may exhibit different characteristics in the size and duration of reliability events as well as performance under extreme "black swan" tail events that could lead to catastrophic system failure. Characterizing these alternative metrics helps differentiate the various portfolios despite their uniform LOLE results.

Two types of detailed reliability analysis are conducted: a "traditional" LOLP study in which Monte Carlo simulations representing hundreds to thousands of years are used to measure a range of statistical reliability metrics, as well as a special resilience study in which the performance of each portfolio is tested against specific high impact, low frequency (HILF) conditions to understand what vulnerabilities may exist.

In the short term, while PNM examines the potential to expand its planning framework, an immediate next step would be to test candidate portfolios from this IRP process against PNM-specific extreme events such as the ones this study considers. All portfolios are tested for resource adequacy, but in the long-term, portfolios should be designed to successfully address both resource adequacy and resilience.

While all candidate MCEP portfolios meet all state and federal clean energy policies, emissions reductions policies, and resource adequacy standards, they do not necessarily exhibit the same performance during specific extreme weather events. In the IRP, PNM tests select portfolios for under both severe winter storms and extreme heat waves to measure seasonal resilience performance under different stress scenarios. The insights from such stress testing can be used to inform future capacity investments. For this IRP, the performance of each portfolio is during HILF weather events is evaluated on the basis of (1) the number of hours of load shedding required, and (2) the amount of load shedding required (measured in GWh)

5.3 Risk Assessment

The development of the IRP includes consideration of a wide range of future risks that could impact PNM's ability to execute upon its plans or the costs, environmental impacts, and reliability outcomes of doing so. These risks are address both quantitatively (where possible) and qualitatively in the IRP portfolio analysis.

Table 32. Consideration of various risk factors in the development of the IRP

Risk Factor	Key Question(s)	Treatment
Resource Development Timelines	To what extent is each portfolio subject to risks associated with project development (e.g., permitting, siting, and other factors)?	Discussed qualitatively in **Section 7.3.8**
Transmission Development Timelines	To what extent does each portfolio require investment in new transmission, and how could those needs impact PNM's ability to bring resources online in a timely fashion?	Discussed qualitatively in **Section 7.3.8**
Operational and Performance Uncertainties	To what extent does each portfolio rely on technologies not commercially available today whose performance in a real-world setting is unknown?	Discussed qualitatively in **Section 7.3.8**
Undepreciated Investments	Do the future investments in new resources expose PNM to risks of stranded assets?	Discussed qualitatively in **Section 7.3.8**
Organized Wholesale Market	To what extent does each portfolio prepare PNM for future opportunities to participate in organized markets in the West?	Discussed qualitatively in **Section 7.3.8**
Market Exposure	How significant a role does the wholesale market play in enabling PNM to maintain reliability?	Analyzed in resource adequacy & resilience studies (**Sections 7.3.5** and **7.3.6**)
Resource Performance	How would resource-specific uncertainties (including the potential for local and/or regional natural gas correlated outages and performance degradation of energy storage) impact reliability outcomes of the portfolio?	Analyzed in resource adequacy & resilience studies (**Sections 7.3.5** and **7.3.6**)
Extreme Weather Events	To what extent do specific extreme weather events pose a risk to reliability?	Analyzed in resource adequacy & resilience studies (**Sections 7.3.5** and **7.3.6**)
Federal Policy	How robust is each portfolio considering potential future changes in clean energy policy?	Explored explicitly in National Climate Policy future and through sensitivity analyses on future carbon prices (**Section 7.3.7**)
Commodity Prices	How does the uncertainty surrounding future commodity prices (including natural gas and carbon prices) affect cost outcomes across portfolios?	Explored through high and low sensitivities on natural gas & carbon prices (**Section 7.3.7**)
Technology Costs	How does the uncertainty surrounding future capital costs of new resources affect cost outcomes across portfolios?	Explored in high and low sensitivities on future technology costs (**Section 7.3.7**)

6 New Resource Options

Chapter Highlights

- PNM's 2023 IRP considers an expansive range of technologies to meet future customer needs, including demand-side resources, renewable resources, storage resources, thermal resources, and complementary investments in new transmission.
- Demand-side resources (energy efficiency and demand response) are modeled consistently with supply-side options to evaluate them on a level playing field. This allows the IRP to expand or contract demand-side programs to maximize cost-effectiveness.
- Generally favorable economics and good weather conditions in New Mexico make wind and solar promising new supply-side options. Likewise, battery storage has emerged as an important flexible resource option, though each of these technologies face challenges that must be considered.
- To meet remaining needs, PNM also considers emerging firm technologies such as long-duration storage and hydrogen-ready generators, at varying stages of development and deployment.
- The economics of all new resource options are evaluated based on forecasted costs to build, operate, and maintain them. For certain options, the price of fuel (natural gas or hydrogen) or other market signals (import and carbon prices) influence their cost-effectiveness.
- Delivery of new generation resources to load will have direct implications for the transmission system. These impacts are accounted for through the application of transmission adders derived from actual project cost estimates to resources based on their assumed locations in the state of New Mexico.

As PNM plans toward a carbon-free goal, a wide range of resource and transmission solutions are considered to fulfill future needs. The solutions evaluated can generally be classified in five categories:

- **Demand-side resources** (Section 6.1) that will modify customers' loads behind the meter;
- **Renewable resources** (Section 6.2) that will supply carbon-free electricity to customers, typically with a profile that varies with meteorological conditions;
- **Energy storage resources** (Section 6.3) that will allow system operators to store electricity during periods of relative surplus and supply it to customers when they need it most;
- **Thermal resources** (Section 6.4) that will rely on combustible fuels to generate power on demand for the benefit of customers;
- **Transmission expansion** (Section 6.5) that will transmit power from the physical location it is generated to the sites of customers' loads.

For the purposes of inclusion in this IRP, the set of technologies modeled is limited based on two criteria: (1) a technology must have achieved a minimum level of commercialization, and (2) its expected cost and performance characteristics must compare favorably with alternative technologies with similar operating characteristics. While these criteria are used to exclude certain technologies from the planning process, PNM will continue to monitor the market across all offerings, and procurement processes will be designed to be agnostic to specific technologies.

Table 33. New resource options studied in PNM's 2023 IRP

Category	Technology	IRA Eligibility[A]	TRL[B]
Demand-Side	Energy Efficiency		n/a
	Demand Response		n/a
Renewables	Solar PV	PTC ($26/MWh)[A]	9
	Wind		9
Energy Storage	Lithium-Ion Battery	ITC (30%)	9
	Flow Battery		8
	Pumped Hydro Storage		9
	Compressed Air Energy Storage		8.7
	Liquid Air Energy Storage		7.5
	Thermal Air Energy Storage		9
	Iron-Air Energy Storage		8
	Hydrogen Electrolysis & Storage	PTC ($3/kg)	6
Thermal	Hydrogen-Ready Combustion Turbine		5
	Linear Generator		8
	Carbon Capture & Storage	ITC (30%)	7-8

Table Notes

A. Wind & solar projects are also eligible for 48E (Clean Electricity ITC) but are assumed to make use of the PTC in this IRP.

B. TRLs for each technology were provided by Sandia National Laboratory.

Most resources considered are available for tax credits included in the IRA. From 2025, all net-zero carbon emission generators are eligible for either the Clean Power ITC (48E) or PTC (45Y), while storage technologies can receive the ITC. As discussed in Section 2.1.1, the expiration date of these credits depends on the emissions of the broader U.S. electricity system, and the assumption used in the IRP is that they will remain available through at least 2042, the end of this IRP's planning period. In addition, some of the new resources under consideration are eligible for tax credits for carbon capture (45Q) or clean hydrogen production (45V), which are available for new projects beginning construction by 2032. This analysis assumes all projects comply with prevailing wage requirements to receive the full tax credit.

To fill the remaining capacity needs, the types of resources needed to ensure resource adequacy will include a diverse mix of technologies and capabilities that generally fall into three categories:

- **Low-cost carbon-free energy resources (CFR)** with the capability to produce clean energy to meet a majority of customers' energy needs throughout the year. Examples available today include solar PV, wind, and energy efficiency.
- **Dynamic balancing resources (DBR)** that provide operators the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of PNM's carbon-free resources will not coincide naturally with

electricity demand. Examples include shorter-duration energy storage, aero-derivative combustion turbines, and demand response.

- **Firm generating resources (FGR)** with the capability to operate at or near full capacity for extended periods of time that will allow operators to maintain reliability even under the most constrained conditions in the system, which may include both periods of high demand as well as periods of low output from variable resources. Today, these needs are met with PNM's nuclear and fossil resources; in the future various emerging technologies including hydrogen and long-duration storage may help to satisfy these needs.

Ownership of new resources may follow three different models: a "utility self-build" project is one that the utility constructs and operates on its own. A "build-transfer" or "turnkey" project is one that is developed by a third party, often an independent power producer (IPP), and then sold to the utility to own and operate. A third approach is for PNM to purchase the output from a generator or set of generators over a contracted period through a PPA. Each of these options has specific benefits, but each also presents risks and uncertainties worth consideration when making procurement decisions.

The long-term resource planning process does not evaluate specific ownership structures, and instead, compares and evaluates all resources under a framework that is agnostic to ownership.[32] To efficiently evaluate projects, a utility ownership finance structure is utilized, but unlike utility ownership, the assumptions is that projects can take full advantage of any tax credits. This approach is not meant to show a preference for utility ownership, but rather to model tax benefits while ensuring that all technologies are considered on a level playing field using a consistent set of financing assumptions.

6.1 New Demand-side Resources

6.1.1 Energy Efficiency

In keeping with PNM's carbon-free goal, future energy efficiency measures are considered beyond the requirements established by the EUEA as a new resource option, building upon the innovative methods piloted in the 2020 IRP to characterize efficiency as a candidate resource option in capacity expansion modeling. The EE beyond planned amounts is bundled into similarly priced groups of different measures, which can be considered by the model alongside supply-side resources. Allowing this EE to be chosen by the model provides insight into which additional EE above and beyond the EUEA requirements may be cost-effective under the utility cost test (UCT) when compared against supply-side alternatives.

To enable modeling EE as a resource, PNM contracted with Applied Energy Group (AEG) to develop updated hourly supply curves representing program potential. The process to develop these bundles consisted of the following steps:

1. Calculate "achievable technical" potential for EE within PNM's service territory. updated calculation was performed to take what is technically and economically feasible, then narrowing it to an achievable amount based on expected adoption rates. This method does not screen for measure benefit/cost ratios; it is used to calculate the total potential, not solely what will be deemed cost-effective.
2. Define a statutory EE bundle based on requirements to meet the EUEA from 2023-2025. This bundle is automatically included in the portfolio to comply with the EUEA targets.

[32] Project specifics, including ownership structures are determined during RFP evaluations.

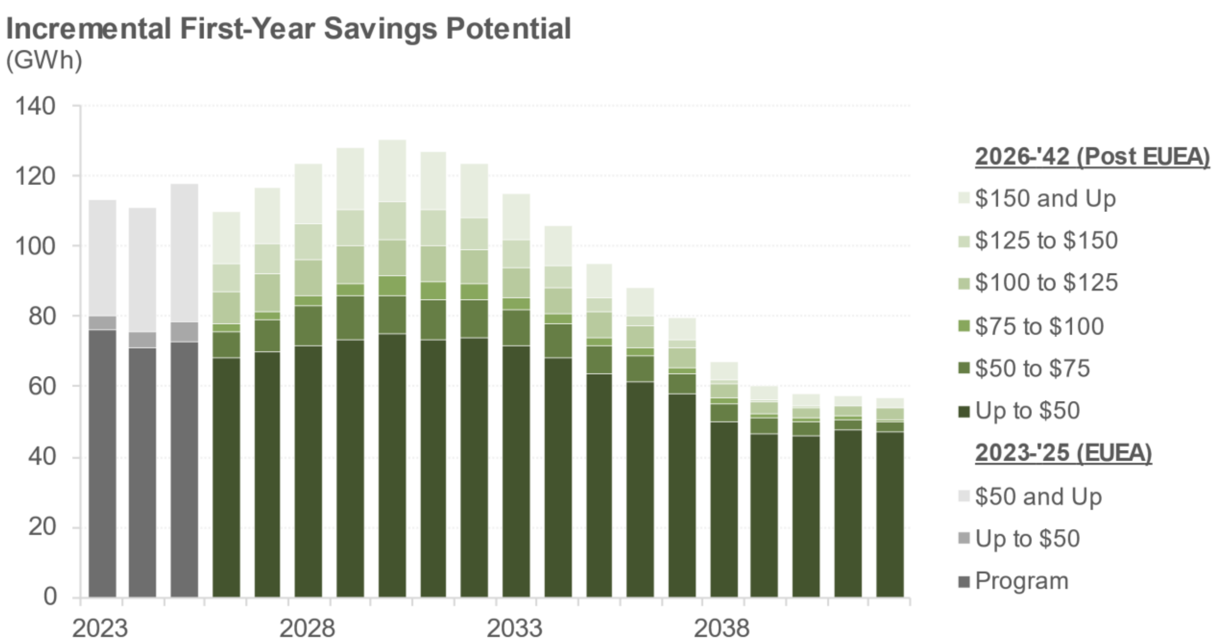
3. Define bundles of EE measures beyond the EUEA's minimum requirements by grouping measures with similar levelized costs of conserved energy. These bundles are provided as candidate resources that the model may select, after the completion of the remaining steps.
4. Calculate annual incremental energy savings, weighted average cost, and measure lifetime for each bundle based on the included measures.
5. Develop hourly impacts for each bundle by spreading measure-level impacts over calibrated end use load shapes.

While this general approach is consistent with the methods used in the last IRP, this IRP process has made several enhancements to the input data developed. Namely:

- The grouping of the measures was updated to focus more on the cost range that is more likely to be on the margin in the IRP model. The lowest cost measures are grouped in one "Up to $50/MWh" bundle; four successive bundles represent pricing increments of $25/MWh (e.g. "$50-75/MWh"); and a final bundle represents measures with a cost above $150/MWh; and
- PNM's accounting of measures available after the EUEA horizon (i.e. beyond 2025) was improved, which results in an increase in the achievable potential represented in the supply curves in that period.

The results of this process are shown in Figure 56, which summarizes the bundles modeled in this IRP; additional details on the characteristics of the bundles are provided in Appendix I. The efficiency measures designated as "Program" are planned efficiency required by statute – this efficiency is included by default across all scenarios. The relatively small amount of potential in the "Up to $50" bundle in these years reflects the fact that most low-cost opportunities for energy efficiency have been exhausted by current programs.

Figure 56. Energy efficiency bundles



Impact at shown at load and not grossed up for transmission & distribution losses

In any given simulation year, the model may select from the additional efficiency bundles incremental to the program bundles shown in Figure 56. If a bundle is selected, its load impacts persist throughout the bundle lifetime.

6.1.2 Demand Response

As discussed in Section **3.2.2**, PNM currently has two demand response programs, both of which currently expire after 2026: Peak Saver (11 MW) and Power Saver (21.5 MW). With an ELCC of 70%, these programs provide a combined 23 MW of firm capacity towards resource adequacy needs. In this analysis, each of these programs can be extended an additional three years (2027-2029); thereafter, a generic DR program with characteristics similar to Power Saver is included in the modeling as a resource option.

Due to the voluntary nature of the DR programs, rules dictating call schedules, and historical underperformance of enrolled MW, it is important to consider DR in the context of the reliability discussion of Section **7.3.5**. The success of a DR program depends on the shape and timing of the system peak relative to the structure of the DR program. For example, the current DR programs, which have 4-hour call durations, cannot mitigate longer peaks. These programs have a limited ability to mitigate fast ramps too: Power Saver has historically provided no contribution to 10-minute response. The presence of more storage may create opportunities for effective optimization of DR and storage discharge, but the value of such optimization declines with program constraints on DR call schedules.

6.2 New Renewable Resources

The emergence of low-cost renewable resources has been one of the most notable developments in the industry in the past decade. During this period, capital costs for new solar and wind generation have declined by 76%[33] and 50%[34], respectively. Accompanied by technological improvements in performance, these changes have significantly reduced the costs to develop these resources and enabled their rapid expansion nationwide.

New Mexico's renewable resource potential is rich – and, unlike many states, offers both high quality solar and wind resources. The location in the southwestern United States has some of the highest quality solar resources across the state and high-quality wind resources in the eastern part of the state. The proximity to such high-quality renewable resources is likely to be a key part of the transition to a carbon-free portfolio.

6.2.1 Solar Photovoltaics

Despite recent development headwinds, solar PV resources remain an attractive source of carbon-free electricity considered in this IRP. New Mexico's climate is conducive to an abundant high-quality solar resource, with favorable conditions for solar power year-round. New Mexico has some of the highest quality solar resource in the southwest region, especially in the southern part of the state.

Assumed Technology Characteristics

Key modeling assumptions for new solar PV resources are shown in Table 34. Cost assumptions for new solar PV resources are based on the results of PNM's recent competitive RFPs and incorporate future technology cost declines based on NREL's 2022 ATB. Although the ITC was historically modeled for solar resources, the clean energy tax credits established by the IRA allow

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[33] NREL, *Summer 2022 Solar Industry Update,* available at: https://www.nrel.gov/docs/fy22osti/83718.pdf

[34] Same as above

solar PV to qualify for the PTC going forward. The relative benefit of ITC and PTC depends on the costs and capacity factor of specific projects. Several analyses have shown that with a relatively high-capacity factor, it is generally more economic for solar resources in the Southwest to opt for PTC. As such, the PTC for solar PV is modeled in this IRP. As discussed earlier in this chapter, the PTC will be available for new projects coming online through the end of the analysis period. A number of sensitivities were examined on future solar PV resource costs, which consider variations in the rate of cost declines.

Table 34. Technology cost & performance assumptions, solar PV resources

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	$1,444	$1,254	$1,338	$1,427
Fixed O&M	$/kW-yr	$23	$23	$26	$29
Capacity Factor[A]	%	32-34%	32-34%	32-34%	32-34%
Production Tax Credit[B]	$/MWh	$44	$51	$59	$68
Operating Life	yrs	30	30	30	30
ELCC	%	Calculated dynamically in model (see Section 7.1)			

Table Notes

A. Capacity factors for new solar PV resources vary by location

B. PTC values reflect a gross-up for taxes and escalate with inflation over time

Transmission Needs

Unlike wind resources, the performance of solar PV generation does not vary considerably based on its location in the state, as the underlying patterns of solar insolation are similar across New Mexico. Accordingly, PNM's plan considers solar PV resources in multiple locations, including areas close to the major load center in and around Albuquerque, as well as the areas to the north, west, south, and east. In each of these areas, new transmission will be needed to accommodate increased levels of solar PV. Different transmission cost adders are applied to candidate solar PV resource in different areas based on the estimated cost for new transmission expansion in the area. Additional detail on the transmission cost adder and the new transmission projects assumed can be found in Section 5.2.2 and Section 6.5.

6.2.2 Wind

Over the past decade, the market for wind generation within the United States has expanded considerably, growing by an average of nearly 10 GW per year since 2015. New Mexico's wind resource potential is significant and has attracted interest from buyers within and outside of the state. The highest quality wind in New Mexico is located in the eastern part of the state, as shown in Figure 57.

Figure 57. Average wind speed in the southwest U.S.

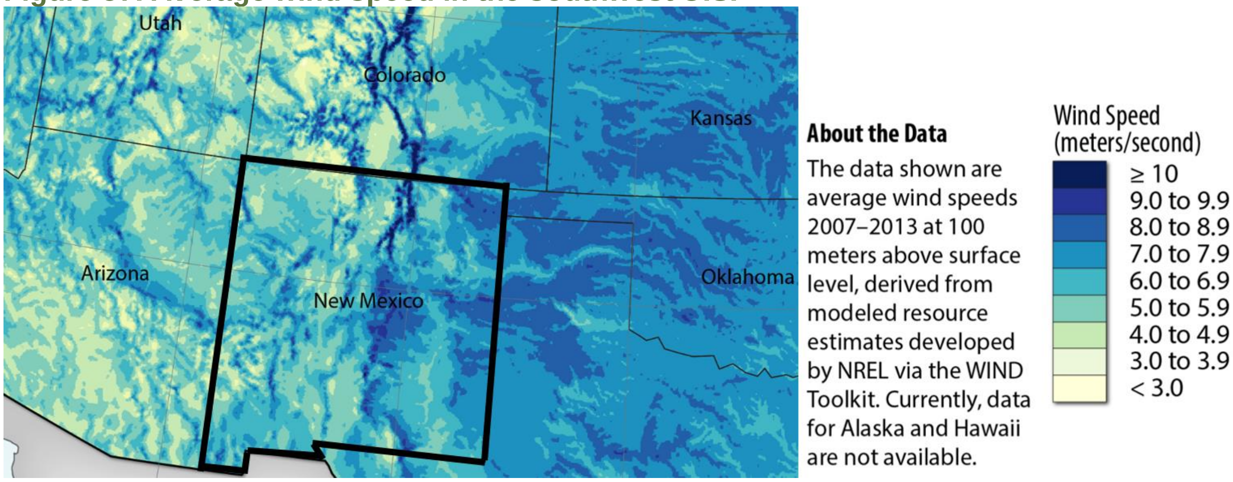

Image source: NREL, *Wind Resource Maps and Data,* available at: https://www.nrel.gov/gis/wind-resource-maps.html

Assumed Technology Characteristics

The high-quality wind resources in New Mexico are generally located in the eastern portion of the state. This area has experienced significant levels of commercial development to supply high-quality wind to PNM and other off takers elsewhere in the Western Interconnection. Wind resources are modeled with a 44% capacity factor based on bids recently received in response to competitive solicitations. Cost assumptions for new wind resources are based on the results of PNM's most recent competitive RFPs and incorporate future technology cost declines based on NREL's 2022 ATB. The IRP assumes wind will continue to opt for PTC and the tax credits will be available for new wind resources through the end of this IRP's planning period. Key cost assumptions for new wind resources are shown in Table 35.

Table 35. Technology cost & performance assumptions, new wind resources

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	$1,682	$1,425	$1,567	$1,738
Fixed O&M	$/kW-yr	$54	$59	$66	$74
Capacity Factor	%	44%	44%	44%	44%
Production Tax Credit[A]	$/MWh	$44	$51	$59	$68
Operating Life	yrs	30	30	30	30
ELCC	%	Calculated dynamically in model (see Section 7.1)			

Table Notes

A. PTC values reflect a gross-up for taxes and escalate with inflation over time

Transmission Needs

New wind resources are most likely to be developed in eastern New Mexico, where most development in the state has historically occurred and the highest quality potential exists. Because the transmission system between eastern New Mexico and Albuquerque is fully subscribed, additional investment in transmission is needed to deliver new wind resources to loads. The 2023 IRP analysis captures this need by including an incremental transmission cost associated with new wind resources based on the characteristics of potential new transmission projects under consideration, as discussed in Section 6.3.

In most scenarios, new wind resources are assumed to be available beginning in 2033, a realistic reflection of the long lead time needed for new transmission expansion to the east. However, in select scenarios, new wind is treated as available beginning in 2028. These specific scenarios help evaluate whether accelerating development of transmission projects to unlock opportunities for wind development in the near term would provide economic benefits to customers. Results of this analysis notwithstanding, timelines associated with siting, permitting and constructing transmission from that region are barriers that are likely to make new development on an accelerated timeline challenging.

6.3 New Energy Storage Resources

To date, the market for grid-scale storage has largely been dominated by lithium-ion batteries, whose additions across the U.S. have accelerated in recent years, reaching nearly 9,000 MW nationally in 2022 and expected to double to 18,000 MW by the end of 2023.[35] At the same time, research and development efforts into alternative forms of energy storage – particularly technologies with longer duration than lithium-ion batteries – have accelerated, and interest in these emerging technologies has grown since the passage of the IRA.

In this IRP, the range of storage technologies considered is considerably more expansive than in past planning efforts. One of the reasons to study a wide range of technologies in the planning process is to better understand what types of characteristics may be of highest value to PNM in the transition to a carbon-free portfolio. However, considerable uncertainty remains as to which emerging storage technologies may ultimately reach commercial viability at competitive pricing; therefore, the study of these range of options is intended to provide an indication of what characteristics may fit best in the portfolio rather than a prescription of preferred technologies.

Cost assumptions modeled for the different energy storage resources are an important input to the IRP. Because of its relative maturity, the quality of pricing data for lithium-ion batteries is higher than other technologies; cost assumptions for lithium-ion storage are based on actual pricing data from projects offered into PNM's recent competitive solicitations and future cost declines projected by NREL's 2022 ATB. Given the lack of maturity across the other emerging energy storage technologies, future cost assumptions are highly uncertain. For this IRP, cost assumptions for the different storage technologies and how they change over time are developed based on the synthesis of information of several different sources:

- Pricing projections provided by developers through PNM's 2022 Technology RFI;
- E3's *Zero-Carbon Technology Assessment*, a review of emerging technologies funded by the California Public Utilities Commission (CPUC) as part of its ongoing IRP proceeding;[36]
- Future technology cost projections provided by Siemens.

6.3.1 Lithium-Ion Battery

Among the various forms of chemical storage, lithium-ion battery storage has quickly emerged as the most competitive technology for short-duration applications (typically applications of up to four hours). Lithium-ion technologies currently have multiple advantages over competing battery

[35] EIA, "Battery Storage in the United States: An Update on Market Trends," available at: https://www.eia.gov/analysis/studies/electricity/batterystorage/

[36] Available at: https://www.ethree.com/wp-content/uploads/2023/03/CPUC-IRP-Zero-Carbon-Technology-Assessment.pdf

chemistries, including a high energy density, better cycle life, and high round-trip efficiency. Because lithium-ion batteries are used in multiple applications—most notably, in electric vehicles as well as stationary applications—competition among vendors and a rapid scale-up of manufacturing experience has helped to drive down costs significantly.

Assumed Technology Characteristics

The IRP analysis models four-hour lithium-ion batteries as an option to meet future capacity and flexibility needs. The assumptions on the present and future cost of battery storage installations are based on a combination of recent bid data provided to PNM and NREL's 2022 ATB and are summarized in Table 36.

Table 36. Technology cost & performance assumptions, four-hour battery storage

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	$1,678	$1,326	$1,377	$1,459
Fixed O&M	$/kW-yr	$34	$34	$37	$40
Duration	hrs	4	4	4	4
Round Trip Efficiency	%	86%	86%	86%	86%
Investment Tax Credit	%	30%	30%	30%	30%
Operating Life	yrs	20	20	20	20
ELCC	%	Calculated dynamically in model (see Section 7.1)			

Table Notes

A. The ELCC analysis for energy storage resources assumes a forced outage rate of 8%, a figure that is informed by real-world performance of existing storage resources in California. See Section 2.2.1 for discussion of information used to inform this assumption.

6.3.2 Flow Battery

Flow batteries, named for the liquids that serve as working fluids and store electricity in tanks, may utilize a number of different chemistries. Relative to lithium-ion batteries, flow batteries are typically more well-suited for longer-duration storage applications (10+ hours), have a relatively lower round-trip efficiency, and are typically more expensive per unit of storage capacity. Today, this is a relatively nascent technology that has not yet been demonstrated at the scale needed to satisfy large-scale grid needs. For this reason, flow batteries are considered as a resource option in a limited set of scenarios.

Assumed Technology Characteristics

Table 37 summarizes the cost and performance assumptions for flow battery storage, which is considered as an option in select scenarios beginning in 2028.

Table 37. Technology cost & performance assumptions, flow battery storage

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	*n/a*	$3,664	$3,830	$4,003
Fixed O&M	$/kW-yr	*n/a*	$24	$26	$28
Duration	hrs	*n/a*	10	10	10
Round Trip Efficiency	%	*n/a*	65%	65%	65%
Investment Tax Credit	%	*n/a*	30%	30%	30%
Operating Life	yrs	*n/a*	20	20	20
ELCC	%	*n/a*	Calculated dynamically in model (Section 7.1)		

6.3.3 Pumped Hydro Storage

Pumped storage is a form of gravitational storage that uses hydraulic pumps to move water from a reservoir at lower elevation to one at higher elevation; water stored at the higher elevation can eventually be run through hydraulic turbines to generate electricity when needed. Unlike many storage technologies studied herein, pumped storage is a mature technology that has been widely deployed.

Several factors currently present barriers to widespread deployment of pumped storage. First, there are a limited number of sites that are suitable for pumped storage development from both a hydrological and permitting perspective. Second, potential projects are generally very large (sometimes described as "lumpy" investments), which makes it difficult for a single offtaker to finance the plant.[37] Third, the timelines for permitting and development of new pumped storage resources are typically longer than many other types of resources and therefore require advanced planning and commitment.

Development challenges notwithstanding, pumped storage is a proven, mature option for longer duration storage whose long storage duration can provide both dependable capacity for resource adequacy and flexibility to balance renewable variability. In this IRP, pumped storage is included in a select set of scenarios to help inform PNM's strategy regarding planning for long lead time investments.

Assumed Technology Characteristics

This IRP includes two discrete options for new pumped hydro– one with an eight-hour duration and one with a 70-hour duration –to help understand the role pumped hydro facilities with different durations might play on the portfolio in the upcoming years. A minimum project size of 300 MW is required for both projects, reflecting the technology's lack of modularity and the likely necessity that PNM take on a large share of a project to effectuate development. Given the relatively long lead time for new pumped storage development due to permitting, development, and potential coordination of joint ownership agreements, the IRP does not consider new pumped storage as an option prior to 2028.

The costs and characteristics of pumped storage facilities are highly site-specific and can vary considerably. The cost and operational assumptions for the representative plant modeled in this IRP are based on information collected from the 2022 technology RFI, as well as input from Siemens and E3. Table 38 and Table 39 summarize the resource characteristics assumed for the two pumped hydro options.

[37] One potential strategy to address this challenge would be to pursue a joint ownership agreement of a new, large, pumped storage project with other utilities or offtakers within the region. Considering the expected regional trends—significant new investments in solar generation coupled with retirements of aging firm resources—it is reasonable to expect that other utilities may be in a similar position by 2030, in search of both dependable capacity for resource adequacy and the storage capability to integrate increasing levels of solar. This type of arrangement would no doubt present its own unique challenges but might provide an avenue for right-sizing a share of a major infrastructure project to meet PNM's specific needs.

Table 38. Technology cost & performance assumptions, representative 8-hour duration pumped storage

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	*n/a*	$3,251	$3,657	$4,187
Fixed O&M	$/kW-yr	*n/a*	$52	$60	$70
Duration	hrs	*n/a*	8	8	8
Round Trip Efficiency	%	*n/a*	79%	79%	79%
Investment Tax Credit	%	*n/a*	30%	30%	30%
Operating Life	yrs	*n/a*	100	100	100
ELCC	%	*n/a*	Calculated dynamically in model (Section 7.1)		

Table 39. Technology cost & performance assumptions, representative 70-hour duration pumped storage

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	*n/a*	$4,567	$5,295	$6,138
Fixed O&M	$/kW-yr	*n/a*	$52	$60	$70
Duration	hrs	*n/a*	70	70	70
Round Trip Efficiency	%	*n/a*	80%	80%	80%
Investment Tax Credit	%	*n/a*	30%	30%	30%
Operating Life	yrs	*n/a*	50	50	50
ELCC	%	*n/a*	99%	99%	99%

Transmission System Impacts

Based on information collected through the 2022 Technology RFI, viable sites for new pumped storage are assumed to be located in the Four Corners region. The analysis assumes that either pumped hydro option would be connected to PNM's northern transmission infrastructure and would incur the first tranche transmission cost adder for projects sited the north zone. Please see Section 6.5.2 for additional information regarding northern transmission cost adder assumptions.

6.3.4 Compressed Air Energy Storage

Compressed air energy storage (CAES) is a form of long-duration storage that uses surplus electricity to compress air to high pressures for storage, usually in a subterranean geologic formation. The compressed air can later be withdrawn and, at high pressure, used to power a turbine to generate electricity. The requirement for a sizeable, enclosed volume in which to store the compressed air requires specific geological conditions, which inherently limits opportunities to develop CAES at scale; however, some potential sites have been identified in New Mexico. CAES has a lower round-trip efficiency than lithium-ion batteries but is more suitable for longer-duration storage. Although a small number of projects are currently operating, to date, CAES has not been widely deployed globally or nationally.

Table 40 summarizes the cost and performance assumptions for CAES, which is considered as an option in select scenarios beginning in 2028.

Table 40. Technology cost & performance assumptions, CAES

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	*n/a*	$3,521	$4,082	$4,732
Fixed O&M	$/kW-yr	*n/a*	$27	$32	$37
Duration	hrs	*n/a*	24	24	24
Round Trip Efficiency	%	*n/a*	60%	60%	60%
Investment Tax Credit	%	*n/a*	30%	30%	30%
Operating Life	yrs	*n/a*	50	50	50
Unforced Capacity	%	*n/a*	95%	95%	95%

Transmission System Impacts

The IRP analysis assumes CAES can only be built in eastern New Mexico as it seems to offer the most likely location for the required geological formations. Therefore, new CAES facilities incurred the east transmission cost adder to allow delivery of energy stored in that region to serve customer requirements.

6.3.5 Liquid Air Energy Storage

Liquid air energy storage (LAES) uses surplus electricity to chill air to very low temperatures that allow for storage in a liquid phase; the significant increase in density due to the phase change allows the air to be stored in above-ground tanks until needed, at which point it is depressurized while running through a turbine. Like CAES, LAES utilizes mature turbine generators, and is suitable for longer-duration storage at a lower round-trip efficiency. Additionally, it does not have the geographical restrictions that are applicable to CAES. While several pilot projects exist, this technology has not yet been commercialized at a grid scale.

A generic LAES facility with a 100 MW capacity and 8-hour duration, beginning in 2028, is included as an option in several scenarios. Future cost assumptions are developed by Siemens, as summarized in Table 41.

Table 41. Technology cost & performance assumptions, LAES

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	*n/a*	$4,250	$4,926	$5,711
Fixed O&M	$/kW-yr	*n/a*	$44	$51	$60
Duration	hrs	*n/a*	8	8	8
Round Trip Efficiency	%	*n/a*	55%	55%	55%
Investment Tax Credit	%	*n/a*	30%	30%	30%
Operating Life	yrs	*n/a*	30	30	30
ELCC	%	*n/a*	Calculated dynamically in model (Section 7.1)		

Transmission System Impacts

Like battery storage, LAES can be sited at nearly any location. LAES is modeled as a new resource option across all local areas analyzed in this IRP, with transmission cost adders reflecting potential transmission investments needed to bring the energy stored at different locations to loads.

6.3.6 Thermal Energy Storage

Thermal energy storage (or thermal storage) uses surplus electricity to heat materials contained in an underground medium or storage tank. These hot materials are then used to transfer heat to a steam generator. The materials used for thermal storage vary; in the 2022 Technology RFI, one specific project proposed a design that an electric heater to heat air, which is then blown into specific geomaterials like basalt. Those geomaterials then function as the working fluid moving heat from the air to the steam generator. The various configurations of thermal storage are at various stages of maturity and may take years to develop and deploy. However, thermal storage has been demonstrated at grid scale as part of concentrated solar power projects, and future thermal storage projects can be easily built at existing steam generators, presenting an opportunity to expand or repurpose existing infrastructure.

Assumed Technology Characteristics

A potential thermal storage facility with a 150 MW capacity and 168-hour duration is included as an option in several scenarios beginning in 2028. Assumptions are summarized in Table 42.

Table 42. Technology cost & performance assumptions, thermal energy storage

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	n/a	$3,293	$3,742	$4,249
Fixed O&M	$/kW-yr	n/a	$114	$132	$153
Duration	hrs	n/a	168	168	168
Round Trip Efficiency	%	n/a	35%	35%	35%
Investment Tax Credit	%	n/a	30%	30%	30%
Operating Life	yrs	n/a	20	20	20
Unforced Capacity	%	n/a	98%	98%	98%

Transmission System Impacts

The IRP assumes thermal storage will be connected to PNM's northern transmission infrastructure and will incur the first tranche transmission cost adder for projects sited the north region. Please see Section 6.5.2 for additional information regarding northern transmission cost adder assumptions.

6.3.7 Iron-Air Energy Storage

Iron-air energy storage is a developing long-duration battery that utilizes the natural rusting process. Surplus electricity is used to reverse the process, converting rust to iron. The battery then takes in air from its surroundings, re-converting the iron to rust and releasing the stored energy as electricity. Iron-air batteries have a very low (less than 50%) round-trip efficiency and are slower to ramp up and down. However, iron-air batteries have the potential to provide upwards of 100 hours of storage. Iron-air storage is a relatively nascent technology that has recently entered the pilot stage.

Assumed Technology Characteristics

Iron-air storage is one of the longest-duration storage options considered at a duration of 100 hours. This resource is included in the analysis beginning in 2028. Assumptions used to model this technology are summarized in Table 43.

Table 43. Technology cost & performance assumptions, iron-air energy storage

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	*n/a*	$2,982	$3,225	$3,492
Fixed O&M	$/kW-yr	*n/a*	$86	$100	$116
Duration	hrs	*n/a*	100	100	100
Round Trip Efficiency	%	*n/a*	38%	38%	38%
Investment Tax Credit	%	*n/a*	30%	30%	30%
Operating Life	yrs	*n/a*	15	15	15
Unforced Capacity	%	*n/a*	97%	97%	97%

Transmission System Impacts

Iron air storage is included in the analysis as new resource options across all local areas analyzed in this IRP, with transmission cost adders reflecting potential transmission investments needed to bring the energy stored at different locations to loads.

6.3.8 Hydrogen Electrolysis and Storage

Electrolysis is an established technology that uses electricity to split water molecules into oxygen and hydrogen, the latter of which can be used as a carbon-free fuel that can be used at a later point in time as an input to generate electricity. In this process, hydrogen serves as a form of long-duration storage. This process has a very low round-trip efficiency – typically on the order of 25% - which is substantially lower than most other storage options but may offer very long duration energy storage (hundreds or even thousands of hours).

Assumed Technology Characteristics

In relevant scenarios, the production, storage, and combustion of hydrogen fuel is represented in the analysis through the coupling of three elements: (1) an electrolysis load; (2) a hydrogen storage "tank"; and (3) a hydrogen-burning CT. All three elements are linked in a closed system such that all fuel produced by the electrolysis load must be stored until is ultimately combusted to produce electricity. Assumptions for the first to components of this system are shown in Table 44; the hydrogen-burning CT is modeled with assumptions consistent with other new CTs studied in the IRP (see Section 6.4.1) In this respect, hydrogen serves as a medium for a long-duration storage resource.

Table 44. Technology cost & performance assumptions, hydrogen electrolysis and storage

Characteristic	Unit	2027	2032	2037	2042
Cap. Cost, Electrolysis	$/kW	*n/a*	$1,351	$1,492	$1,642
Cap. Cost, Storage	$/kW	*n/a*	$1,199	$1,390	$1,611

Fixed O&M	$/kW-yr	*n/a*	$135	$149	$165
Production Tax Credit	$/kg H_2	*n/a*	$3	-	-
Electrolysis Efficiency	%	*n/a*	70%	70%	70%
Operating Life	yrs	*n/a*	20	20	20

Under the IRA, facilities that achieve operations by 2035 and produce hydrogen with an embedded carbon intensity of less than 0.45 lbs/MWh are eligible for a PTC of $3/kg. At the time of publication of this IRP, the US Treasury has not yet issued guidance on the details of how embedded carbon intensity will be measured. Accordingly, this IRP conservatively assumes that hydrogen electrolysis loads must be served by dedicated renewable energy resources.

Transmission System Impacts

The location of an electrolysis load and storage system is often dependent on the type of storage. For example, utilizing naturally occurring underground caverns limit the locations available. In this IRP, electrolysis loads can be paired with above-ground tanks if necessary and sited in any local areas, however, to lessen the modeling requirements, the hydrogen electrolysis and storage are assumed to be located in PNM northern region along with the associated transmission cost adder.

6.4 New Thermal Resources

Thermal resources are generating resources that produce electricity by using some form of heat – typically created through combustion of a fuel – to power a turbine. The options for thermal resources considered in this IRP represent potential innovative solutions that may contribute to PNM's transition to a carbon-free portfolio. These include both investments in new technologies and retrofits of existing fossil-fueled resources to reduce or eliminate their emissions.

6.4.1 Hydrogen-Ready Combustion Turbines

A promising pathway based on technology that exists today is the conversion of natural gas-fired generators to burn a carbon-free fuel, such as green hydrogen produced through emissions-free resources, to provide peaking capacity. This IRP evaluates the option of building new hydrogen-ready combustion turbines to meet future resources needs, assuming the plants will initially operate using natural gas fuel but will be converted to operate using hydrogen by 2040. Only natural gas technologies that may be converted to burn 100% hydrogen fuel in the future are considered to increase likelihood that these investments can remain in use beyond 2040. This option builds upon the assumption that hydrogen could be purchased as a commodity by 2040, similar to how PNM purchases natural gas to fuel its natural gas generators today.

Combustion of hydrogen to produce electricity presents some engineering challenges in comparison with the operation of natural gas power plants. Namely, hydrogen's lower volumetric energy content necessitates a higher flow rate, which in turn requires that plants be designed with specialized equipment and accessories. Many modern aeroderivative turbines are capable of operating with a blend of hydrogen and methane fuel – some as high as 90% hydrogen by volume – but will require some limited component changes to enable direct combustion of 100% hydrogen.

While the capability to burn hydrogen is a prerequisite for consideration in the IRP analysis, it is worth noting that hydrogen is not the only carbon-free fuel that these types of plants could consume while transitioning toward a carbon-free portfolio. Renewable natural gas and synthetic hydrocarbons are also potential fuel sources, and the capability of these plants to combust any of these fuels helps preserve flexibility in any plan that includes combustion turbines as new resources.

Assumed Technology Characteristics

The cost and performance assumptions are based on a GE LM6000 combustion turbine and are summarized in Table 45. If selected prior to 2040, new combustion turbines operate using natural gas and are assumed to convert to hydrogen in 2040 (incurring a one-time capital upgrade cost to address the engineering challenges described above).

Table 45. Key input assumptions for new combustion turbines

Characteristic	Unit	2027	2032	2037	2042
Capital Cost[A]	$/kW	$1,457	$1,571	$1,783	$2,023
Fixed O&M	$/kW-yr	$42	$49	$57	$66
Variable O&M	$/MWh	$12	$13	$16	$18
Heat Rate	Btu/kWh	9,747	9,747	9,747	9,747
Operating Life	yrs	40	40	40	40
Unforced Capacity	%	97%	97%	97%	97%

Table Notes

A. In addition to this capital cost, a nominal one-time conversion cost of $585/kW is assumed for all new combustion turbines, treated as an expense in 2040, to allow combustion of 100% hydrogen. This conversion cost is also applied to existing CTs at La Luz and Lordsburg in scenarios in which those plants are converted to hydrogen.

Transmission System Impacts

Siting combustion turbines are generally not constrained to specific locations; however, they are typically in proximity to natural gas pipeline systems. This IRP modeled combustion turbines as options across all local areas analyzed in this IRP, with transmission cost adders based on the location of the project. Additionally, the conversion of existing combustion turbines may not require additional transmission.

6.4.2 Linear Generator

Linear generators are a novel, firm thermal resource which offers an alternative to combustion turbines. Linear generators work by driving the oscillation of copper coils attached to magnets. The constant back-and-forth motion of the magnets produces electricity. The coils oscillate repeatedly as air and fuel are compressed in an inner chamber, pushing the coil outward; followed by the compression of air in the outer chamber pushing the coil back inward.

Linear generators possess multiple advantages over traditional combustion turbines: (1) they produce minimal criteria pollutants such as NOx, (2) they can switch between fuels (e.g. natural gas to hydrogen) without any significant capital expenditures or upgrades, and (3) they can be built in small, modular units to fulfill specific locational needs to mitigate need for new transmission, much like battery storage. Linear generators are currently more costly than traditional thermal generators and have only been deployed at a small scale to date.

Assumed Technology Characteristics

The assumptions for the cost and operating characteristics of linear generators are based on estimates by Siemens, as summarized in Table 46. Like hydrogen-ready combustion turbines, new linear generators are assumed to operate using natural gas fuel until 2040; however, no capital upgrades are needed to do so, as the linear generator technology is already technically capable of operating using hydrogen fuel. In relevant scenarios, linear generators are first included as an option in 2028.

Table 46. Key input assumptions for new linear generators

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	*n/a*	$2,328	$2,459	$2,681
Fixed O&M	$/kW-yr	*n/a*	$38	$45	$52
Variable O&M	$/MWh	*n/a*	$0	$0	$0
Heat Rate	Btu/kWh	*n/a*	8,171	8,171	8,171
Operating Life	yrs	*n/a*	40	40	40
Unforced Capacity	%	*n/a*	98%	98%	98%

Transmission System Impacts

Like combustion turbines, linear generators can be sited as needed near load pockets or in remote locations, thus linear generators are modeled as options across all areas analyzed in this IRP, with transmission cost adders based on the location of the project.

6.4.3 Carbon Capture and Storage

Carbon capture and storage (CCS) is an option that could contribute to PNM's carbon-free goal while continuing to allow for the use of natural gas as a cheaper fuel than hydrogen or other alternatives. Two options for CCS are studied in this IRP: (1) converting an existing generator at Afton to utilize post-combustion CCS, and (2) building a new NET power plant:

- **Retrofits to existing plants** would allow conversion to CCS through chemical absorption, where the exhaust gas runs through a solution that separates the Carbon dioxide, which can then be sequestered. Existing systems that use chemical absorption often achieve 90% capture rates, though near-100% capture is possible at additional cost.
- **NET power plants** utilize an Allam power cycle which works like a traditional turbine but replaces steam with Carbon dioxide. The Carbon is fully contained within the generator, which achieves a 100% capture rate. Additionally, NET power plants do not emit criteria pollutants such as NOx.

There are a handful of existing projects online for both forms of CCS, but neither has been deployed at a level necessary to serve large-scale grid needs.

Assumed Technology Characteristics

This IRP's assumptions for the conversion of an existing generator to CCS are developed from E3 and Siemens estimates, while assumptions for a NET Power Plant use an estimate made by Siemens, as summarized in Table 47 and Table 48. Additionally, the IRA created a new tax credit for sequestered carbon dioxide, which is available for a ten-year period for facilities beginning construction by 2032.

Table 47. Cost & performance characteristics, Afton conversion to CCS

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	n/a	$2,068	$2,398	$2,780
Fixed O&M	$/kW-yr	n/a	$56	$65	$75
Variable O&M	$/MWh	n/a	$9	$10	$12
Heat Rate	Btu/kWh	n/a	9,216	9,216	9,216
Investment Tax Credit	%	n/a	30%	30%	30%
Operating Life	yrs	n/a	40	40	40

Table 48. Cost & performance characteristics, NET power plant

Characteristic	Unit	2027	2032	2037	2042
Capital Cost	$/kW	n/a	$3,723	$4,061	$4,509
Fixed O&M	$/kW-yr	n/a	$122	$141	$163
Variable O&M	$/MWh	n/a	$0	$0	$0
Heat Rate	Btu/kWh	n/a	7,446	7,446	7,446
Investment Tax Credit	%	n/a	30%	30%	30%
Operating Life	yrs	n/a	40	40	40

Transmission System Impacts

Both CCS options would be installed at existing plant sites, thus no significant new transmission facilities would be required and therefore no material transmission cost adders were applied in the analysis.

6.5 New Transmission Options

While New Mexico has significant, high-quality wind and solar resource potential, many of the most suitable sites are located far from the load centers. Because the current transmission system is nearly fully subscribed, many of these new resources require complementary investments in new transmission to facilitate delivery to load.

6.5.1 Transmission Planning Processes

Numerous organizations are involved in planning coordination of the western grid. In addition to the planning meetings that PNM sponsors twice per year, PNM also participates in the WECC Reliability Assessment Committee (RAC), WestConnect Planning Management Committee, and the Southwest Area Transmission Planning Oversight Committee (SWAT).

New operating ideas or concepts start in small regions of the system and, as they are tested and evaluated, they are shared with neighboring utilities. It is important that PNM continues its participation because it allows the company to leverage lessons learned from others.

PNM Local Transmission Planning Process

PNM's Transmission Planning process is performed annually, in accordance with North American Electric Reliability Corporation (NERC) standard TPL-001-5.1 Transmission System Performance

Requirements. Planning processes across the country follow these standardized rules to ensure consistency and best practices across the interconnections. PNM is a NERC-registered Planning Coordinator and Transmission Planner and in those roles, has responsibility for ensuring the reliability of the transmission system though the ten-year planning horizon.

PNM’s Planning Coordinator area is modeled using the most up-to-date information available at the time of each annual assessment including forecasted loads and all planned facility changes. The load levels included in the system models are based on PNM’s and PNM network transmission customers’ most recent load forecasts. The transfers modeled in the system models are based on the regionally developed, and WECC approved base cases that include firm transfers as well as anticipated transmission commitments. The planning cases underpinning the analyses include both on-peak and off-peak system conditions and various years in the planning horizon.

Like the IRP, PNM’s transmission planning process is intended to facilitate a timely, coordinated, and transparent process that fosters the development of electric infrastructure that maintains reliability and meets load growth so that PNM can provide reliable and cost-effective service. However, PNM’s transmission planning process includes customers beyond those considered in the IRP, as it includes all transmission customers (native loads, network and point-to-point customers), rather than just being limited to a retail focus.

The PNM Planning Assessment is part of an annual process to identify needed transmission system reinforcements to ensure adequate transmission capacity is available to meet future obligations at the lowest reasonable cost. These obligations include PNM’s service to its retail customer base in New Mexico, network customers and wholesale wheeling services on behalf of other New Mexico based entities or as otherwise required by FERC.

The PNM Planning Assessment consists of a steady state analysis, stability analysis, and short circuit analysis. More recently, Short Circuit Ratio studies and Electromagnetic Transient (EMT) (SHCR) studies have become necessary to better understand the interactions and impacts of inverter-based resources. Each of these types of analyses are used to ensure PNM’s system meets all mandatory planning criteria. Where planning criteria deviations are identified, PNM develops Corrective Action Plan(s) to ensure system performance meets criteria throughout the planning horizon.

Steady State analysis includes Near-Term Planning Horizon sensitivity analysis and known outage analysis. To demonstrate the PNM system meets performance requirements, the steady state analysis examines system performance for various single contingency and multiple contingency events.

Voltage Stability Analysis is also performed pursuant to WECC criterion.

Stability Analysis consists of analysis to ensure the system remains stable and maintains synchronism with the interconnection when subjected to disturbances such as faults on transmission lines, generator loss, and or significant load loss. Stability can generally be defined as the system’s ability to maintain an equilibrium during normal conditions and following disturbances.

To demonstrate the PNM system meets performance requirements, the stability analysis examines system performance under for all potential system events as outlined in the reliability standards. If marginal concerns are identified, further investigation, including more outages in the area, will be performed. Again, PNM follows the stability planning criteria defined by NERC in Reliability Standard TPL-001-5.1. System performance issues are identified using established system performance criteria. System improvements are recommended to mitigate any unacceptable performance deviations.

Short circuit analysis evaluated circuit breakers to ensure they will not exceed their interrupting capability for faults that they are expected to interrupt over the planning horizon. System performance deviations are also defined in NERC TPL-001.

As inertial resources (large rotating machines) such as thermal generators are replaced with inverter-based resources, studies of Short Circuit Ratio, which is a critical indicator of the power system's strength, is also performed to ensure sufficient short circuit ratio is maintained across the system. The higher the SHCR, the better the system is at absorbing the impact of disturbances such as voltage and frequency deviations. Projects to mitigate insufficient SHCR are recommended as part of this analysis.

Electromagnetic transient studies are a newer addition to transmission planning processes but have become necessary with the proliferation of inverter-based resources to help ensure proper sub synchronous control system interactions and ensure the proper EMT response of the system to disturbances.

WECC Planning Committees

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

PNM participates in the planning functions of WECC through the Reliability Assessment Committee (RAC). PNM has membership in several of the RAC subcommittees and workgroups that focus in varying degrees on transmission planning and coordination activities. The RAC charter includes the following:

- Create and promote a common understanding and broad view of reliability and identify potential reliability risks to the Western Interconnection.
- Review, assess, and report on the overall electric generation and transmission reliability (including resource adequacy) of the interconnected BPS, both existing and as planned.
- Assess and report on the key issues, risks, and uncertainties that affect, or have the potential to affect, the reliability of existing and future electric supply and transmission.
- Work with WECC staff and the Reliability Risk Committee (RRC) to develop and maintain an ongoing, prioritized list of known and emerging reliability and security risks facing the Western Interconnection.
- Coordinate and collaborate with WECC staff and the RRC to perform reliability assessments.
- Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on BPS reliability.
- Investigate, analyze, and report on potential impacts of new and evolving electricity market practices, and new or proposed regulatory and policy framework as appropriate.

- Develop and maintain reliability assessment models and data for use by WECC and Western Interconnection utility planners, planning regions, and stakeholders. This includes those related to future infrastructure needs and current and future trends affecting the reliability of the Western Interconnection.
- Recommend the development of Reliability Standards and Regional Criteria based on reliability assessments.
- Develop and approve RAC protocols as necessary.
- Coordinate the activities of and resolve any conflicts between its subcommittees.
- Review reports and recommendations concerning reliability and provide timely comments and/or recommendations to the WECC CEO and Board.
- Oversee the process necessary to create and maintain the Anchor Data Set (ADS).
- Provide a forum for discussing potential reliability issues, including but not limited to those resulting from efficiency/economics, socio-political considerations and system resource and transmission adequacy.
- Work collaboratively with WECC management in providing input to the WECC strategic plan and in developing the three-year operating plan including consideration of resource needs.

WestConnect Planning Committee

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

Southwest Area Transmission Planning Oversight Committee

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

Other Transmission Planning Committees

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

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

Regional and National Transmission Assessments (Completed and On-going)

The following list of studies are those PNM have followed to help enhance its broader understanding of the industry evolution, study approaches, and conclusions to inform its own evaluation and planning efforts. Most have been completed, with the NERC study just commencing.

- **Princeton Net Zero America Study:**[38] this study evaluated five technological pathways to reach a national goal of net-zero emissions by 2050, using existing technology and costs based on historical energy spending. The results provide a detailed, state-by-state level review of the scale and pace of technology and capital mobilization needed across the country to decarbonize the economy. Results were published in December 2020.
- **NREL Interconnections Seam Study:**[39] This study quantified the costs and benefits of strengthening the connection (or seam) between the Eastern and Western Interconnections to encourage efficient development and utilization of U.S. energy resources. The results show significant value to increasing the transmission capacity between the interconnections. PNM is directly located on an interconnection seam between the Western and Eastern Interconnections.
- **DOE National Transmission Planning Study:**[40] This study identified transmission options to enables help informs regional transmission planning processes, identify pathways for transmission system expansion that meet both regional and national interests including enabling decarbonization while maintaining system reliability. The study was performed in partnership with the Pacific Northwest National Laboratory and the National Renewable Energy Laboratory, along with guidance from a diversely populated Technical Review Committee.
- **DOE National Transmission Needs Study:**[41] This study assessed publicly data, including historic and future needs from more than 120 sources to identify potential transmission solutions to enable greater interregional transmission capability interchange. Unlike the National Transmission Planning Study, this did not identify key national needs that can inform investments and planning decisions. Rather, gave some overview of the potential magnitude of need between areas subregional. This study provided PNM insight into the transmission need on a broader regional basis.
- **WECC Extreme Weather Assessment:**[42] This study evaluated the potential impacts of an extreme cold weather event on the reliability of the system 10 years in the future using a benchmark extreme cold weather event (December 21-26, 2022), which brought very

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[38] The final report and supporting materials from the Net-Zero America study is available at: https://netzeroamerica.princeton.edu/

[39] NREL's Interconnections Seam Study was published by the journal *IEEE Transactions in Power Systems*; a summary slide deck is available at: https://www.nrel.gov/analysis/seams.html

[40] Materials related to US DOE's National Transmission Planning Study are available at: https://www.energy.gov/gdo/national-transmission-planning-study

[41] The full report for the National Transmission Needs Study can be accessed at: https://www.energy.gov/gdo/national-transmission-needs-study

[42] WECC's final report is available at: https://www.wecc.org/Administrative/Year-10%20Extreme%20Cold%20Weather%20Event%20Report%202023.pdf

low temperatures, heavy snow, and high winds to much of the United States and parts of Canada. Study results were published in November 2023.

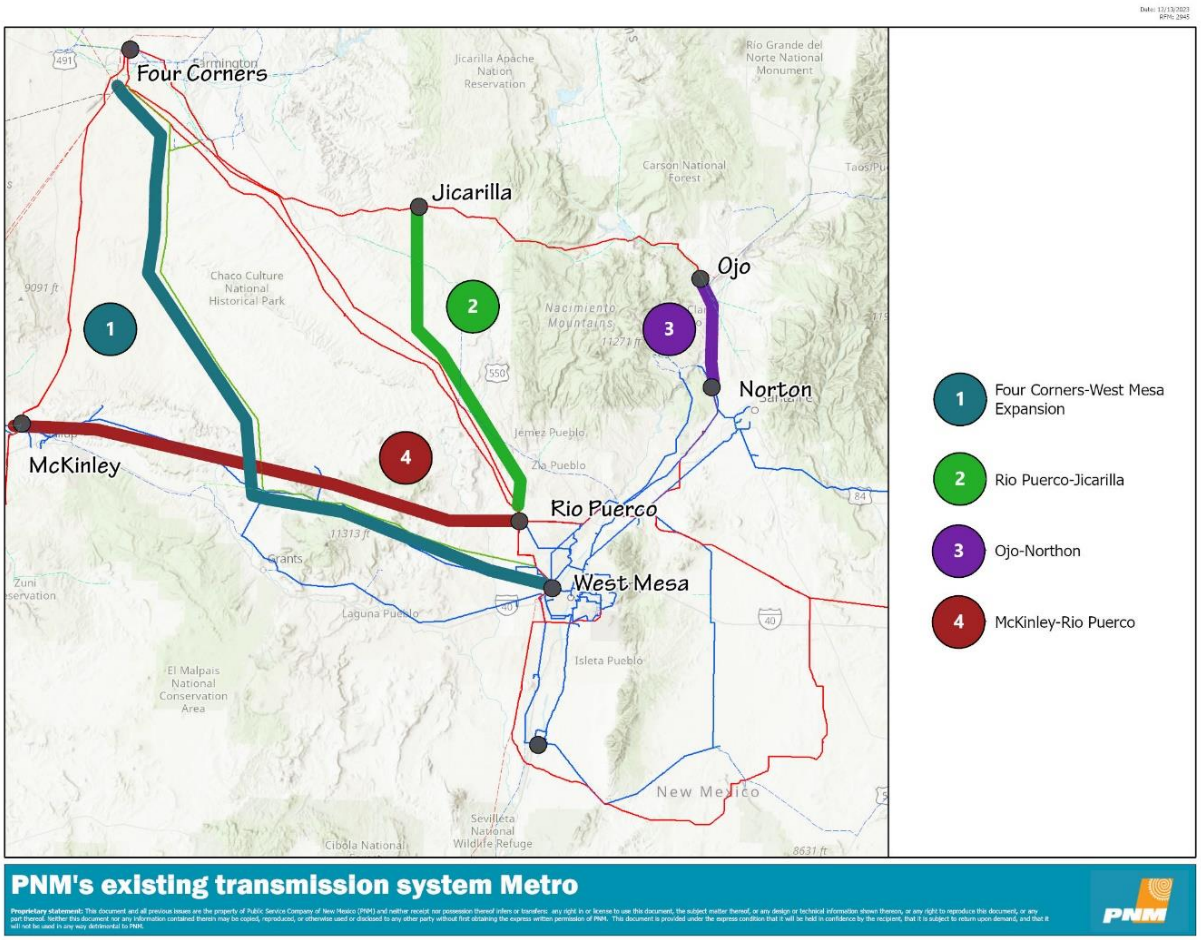
- **NERC National Transmission Interregional Transfer Capability Study:** Pursuant to the provision in the Fiscal Responsibility Act of 2023 requiring NERC to conduct a study on the recommend transfer capability enhancements needed for reliability between neighboring transmission planning areas. NERC, in consultation with the Regional Entities and industry stakeholders will conduct transfer capabilities studies which will be completed within 18 months.

6.5.2 Transmission System Upgrades

During its annual study processes, PNM's transmission planning group has identified several specific potential transmission upgrades throughout PNM's system that would enhance the transfer capability between locations for new generation and load centers. The costs associated with these projects are incorporated into the IRP analysis by applying transmission adders to resources based on their prospective locations throughout the state.

Transmission is inherently a lumpy investment, and siting, permitting, cost, and construction timelines for new transmission line projects will continue to be a challenge. It is accordingly important for the IRP process to provide an early indication of the types, locations, and scale of transmission investments needed to complement the future generation portfolio long in advance of the time they are needed. Some of the conceptual transmission projects under consideration represent reinforcements and upgrades to existing transmission corridors to increase the capacity to deliver renewables to loads. While these types of projects are smaller in scope than projects requiring new corridors and right of way, they nonetheless require significant up-front planning, as the permitting and construction processes together can still take up to a decade in some cases.

Figure 58. Conceptual transmission upgrades delivering to northern New Mexico load centers



Most of these candidate projects were identified several years ago, and indeed served as the basis for transmission cost assumptions used in the 2020 IRP. Since that time, constraints in upstream supply chains and inflationary pressure have led to significant increases in the cost of transmission equipment, and PNM's transmission planning team has provided revised cost estimates for these projects that are reflective of the current market environment. Current cost estimates, all expressed in 2025 dollars, along with the estimated incremental transfer capability associated with each project, are shown in Table 49.

Table 49. Cost and transfer capabilities associated with new transmission projects

Transmission Project	Region	Capital Cost ($ million)	Transfer Capability (MW)	Unit Cost ($/kW)
Four Corners-West Mesa Expansion	North	$964	600	$1,607
Rio Puerco-OJ West Transmission Project	North	$403	600	$673
Ojo-Norton Transmission Project	North	$206	600	$344
McKinley-Rio Puerco Transmission Project	West	$754	600	$1,258
Western Spirit-Pajarito Expansion	East	$652	800	$815
Belen-Person 115 kV	Load	$166	300	$554
Rio Puerco-KM-BW 115 kV	Load	$146	200	$731

The unit costs in the table above constitute the basis for transmission cost adders applied to resources in different regions of the state. The cost adders are included in the model with the following representation:

- The first five projects are modeled directly according to the transfer limits and unit costs represented in the table above.
- The costs of the two load-side projects – the Belen-Person 115 kV line and the Rio Puerco-KM-BW 115 kV line – are averaged with one another to create a generic unit cost for projects located near the load center, which is $625/kW. This unit cost applies to a limit of 300 MW of new load-side capacity.
- Because no generic transmission projects have been identified in southern New Mexico that would deliver to the southern load center,[43] a weighted average cost of the unitized transmission costs is used for other regions of the state, resulting in a transmission adder of $901/kW.
- Once the limits associated with these generic projects have been reached, an additional generic transmission cost adder is applied.

Additional details on the generic projects are provided below.

Four Corners-West Mesa Expansion

The Four Corners-West Mesa Expansion would allow for delivery of up to 600 MW of new resources from northwestern New Mexico to the load center in Albuquerque. The project would include the following elements:

[43] Specific projects have not been proposed for expansion of transmission between Northern and Southern New Mexico. Projects would be expected to have high costs and long lead times. Past studies have looked at possible means of connecting or enhancing existing 345 kV facilities running from Albuquerque to Las Cruces and approximately Saint John, Arizona to Deming to provide for better utilization of the facilities. These assets are primarily owned by El Paso Electric Company. PNM may have some limited remaining opportunity to move resources to Northern New Mexico from areas around Lordsburg or Deming by purchasing wheeling from neighboring transmission providers. It is expected that PNM will continue to need resources located in southern New Mexico to serve existing loads in the area.

- Expand Four Corners and West Mesa 345 kV substations
- Install 345 kV stations and 345/230 kV transformers at Pillar, Bisti, and Ambrosia
- Install two 345 kV switchable shunt reactors
- Rebuild Four Corners-West Mesa 230 kW to 345 kV line (180 miles)

Rio Puerco-OJ West Transmission Project

- Expand Rio Puerco and OJ West 345 kV substations
- Install two 345 kV switchable shunt reactors
- Build OJ West-Rio Puerco 345 kV line (80 miles)

Ojo-Norton Transmission Project

- Expand Ojo and Norton 345 kV stations
- Build Ojo-Norton 345 kV line (34 miles)

McKinley-Rio Puerco Transmission Project

The area West of Albuquerque has considerable potential for solar resources and includes wind resources that have potential for expansion. Transmission facilities in the area include two 115 kV lines with capacity that is fully committed to existing resource obligations. Resource additions on Albuquerque's West Mesa can potentially be accommodated with addition of 115 kV transmission between northern Sandoval County and southern Bernalillo County. Resources further west may require more extensive transmission including 345 kV transmission additions extending from the Arizona border to Albuquerque.

- Expand McKinley and Rio Puerco 345 kV substations
- Build McKinley-Rio Puerco 345 kV (125 miles)
- Install two 345 kV switchable shunt reactors
- Install 345/115 kV transformer and new 345 kV & 115 kV stations

Western Spirit-Pajarito Expansion

- Expand Western Spirit & Pajarito 345 kV stations
- Build Western-Spirit Pajarito 345 kV (135 miles)
- Install 345 kV series compensation
- Install two 345 kV switchable shunt reactors

Belen-Person 115 kV

Numerous solar projects have been proposed which are south of the Albuquerque metropolitan area in Valencia County. Gas resources and recent distribution connected solar projects in the area have resulted in fully subscribed transmission capacity between Belen and Albuquerque. Transmission enhancements will be needed to locate additional resources in Valencia County. PNM has an existing 115 kV line operating at 46 kV which shares poles with an existing 115 kV line to Tome. Conversion of this line to 115 kV operating will provide approximately 100 MW of additional capacity. Studies performed for interconnection requests have also shown that capacity could be added by rebuilding existing circuits south of Huning Ranch. Such efforts would be expected to have at least a 3-year lead time.

- Convert BP 46 kV line to 115 kV
- Expand Belen and Person 115 kV stations
- Reconductor existing Person-Prosperity-KAFB 115 kV line

Rio Puerco-KM-BW 115 kV

- Expand Rio Puerco 115 kV Station (potential satellite station)
- Build 115 kV substation on KM line
- Build 115 kV line from Rio Puerco 115 kV to KM substation
- Expand the Petroglyph 115 kV substation
- Build 115 kV line from KM Line 115 kV substation to Petroglyph 115 kV substation

6.5.3 Merchant Transmission Projects

New Mexico's high quality renewable resources has attracted significant commercial interest from off takers throughout the West, which has in turn led to proposals for several merchant transmission projects to deliver those resources to various load centers in the region. Today, new regional transmission projects are in various stages of development within New Mexico. These projects, summarized in Figure 59, include the following:

- **Vista Trail (345 kV) and the Mora Line (115 kV):** projects under development by Lucky Corridor LLC that would enable increased transfer capability towards the Four Corners area from northeastern New Mexico and southeastern Colorado. This area has significant wind resources but extremely limited transmission infrastructure due to the rural population of the area and its location at the far eastern edge of the Western Interconnection.

- **Southline (345 kV):** a project under development by Southline Transmission LLC consisting of a new right-of-way and an upgrade of an existing corridor linking New Mexico to wholesale markets in Arizona. Phase 1 of this project recently received a DOE grant award through the Bipartisan Infrastructure Law's Transmission Facilitation Program.

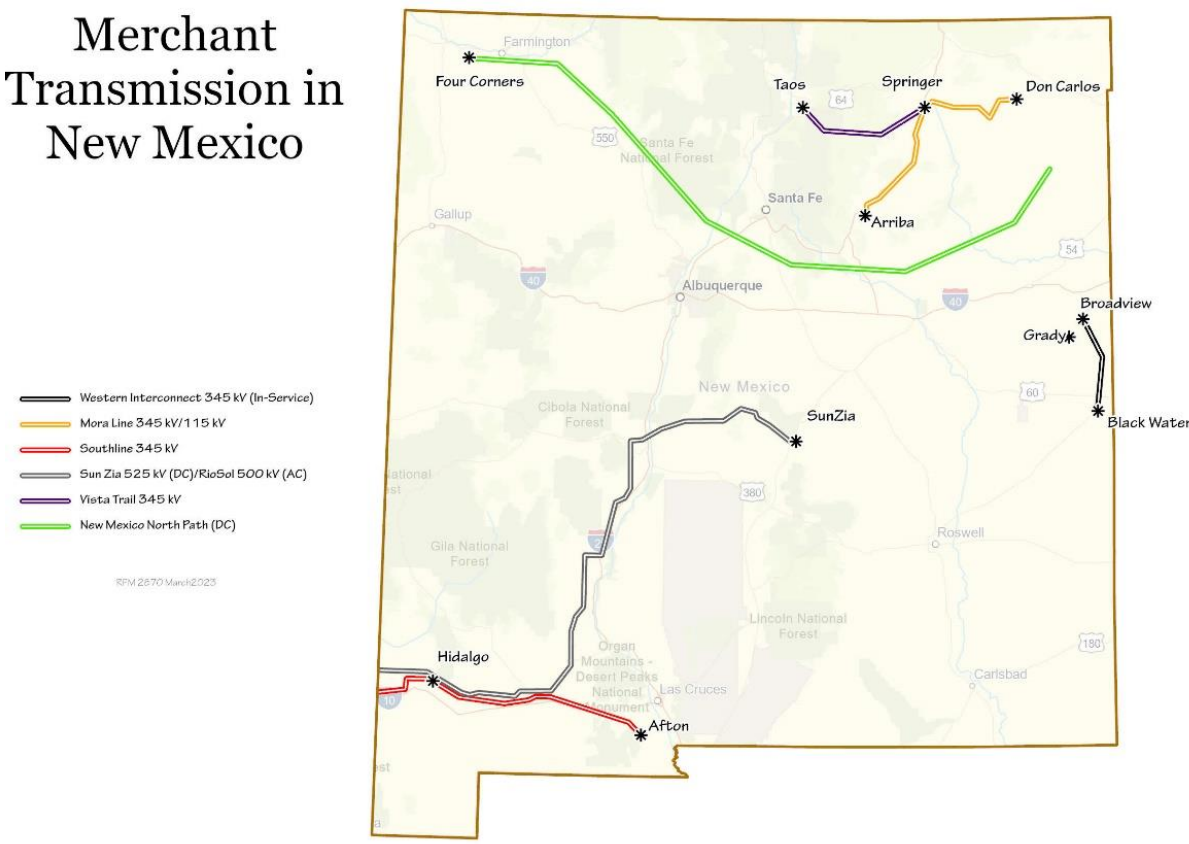
- **SunZia (500 kV):** a new high voltage direct current (DC) transmission line under development by the Pattern Energy from central New Mexico to Arizona. The project broke ground on September 1, 2023.

- **Rio Sol (345 kV):** a new high voltage line under development by Pattern Energy from central New Mexico to Arizona. This will potentially tie into the AC system in New Mexico.

- **New Mexico North Path (500 kV):** Invenergy Transmission is developing New Mexico North Path which is a direct current (DC) transmission line that will deliver energy from northeastern New Mexico to the Four Corners area.

- **Integration of Generation Ties (345 kV):** Wind developers in eastern New Mexico have built several radial 345 kV lines to connect wind resources to PNM's transmission system. Depending on additional resource needs in eastern New Mexico it is possible that some of these additions could be integrated into the looped system enhancing transfer capability.

Figure 59. Merchant transmission projects in development in New Mexico



A number of these projects are designed to transmit renewable electricity out of New Mexico to utilities in California, Arizona, and potentially elsewhere. The configuration of these lines – particularly SunZia, New Mexico North Path, and Southline – does not present a significant opportunity to PNM to develop and deliver resources to PNM's loads under currently planned configurations. Additional studies may show opportunities to better integrate the facilities to serve New Mexico load. Nonetheless, PNM will continue to monitor new opportunities presented by merchant transmission developers (or other potential partners) as PNM pursues its plans to develop renewables within the state.

6.5.4 20-Year Transmission Planning Study

In 2023, PNM scoped and began a 20-year transmission planning study to look at potential transmission solutions to enable increased renewable capability and ensure long-term reliability for the decarbonized system.

The study specifically goes beyond the traditional 10-year study horizon and identify the expected material transmission needs for PNM in support of the Most Cost-Effective Portfolio(s) of its IRP and the year in which PNM projects the transmission need might be most cost-effectively met, based on the most recently available forecasted future system conditions. The study will identify the most cost-effective group of transmission projects that may reasonably meet PNM's transmission needs for reliability and renewable generation integration going out to the 2043.

The study will use multi-scenario analysis which is a technique for considering uncertainties that may impact decision-making in today's world based on potential future conditions. It may be useful when evaluating long-term investments despite the inability to accurately predict future conditions. While it is impossible to predict the future with complete accuracy, scenario development will assist PNM and stakeholders with the identification of strategic choices that utility planners, project developers, regulators, and advocates may reasonably need to consider over the next two decades.

The study will also identify reasonable alternatives available to PNM to meet transmission needs including transmission projects that could be pursued by PNM, and publicly identifiable transmission projects known to PNM that could be pursued with other electric utilities in the region or merchant projects developers.

The study is expected to take one year and be completed by the end of 2024. PNM plans to make the results of the study publicly available to aid in furthering the pursuit of a carbon-free future in New Mexico.

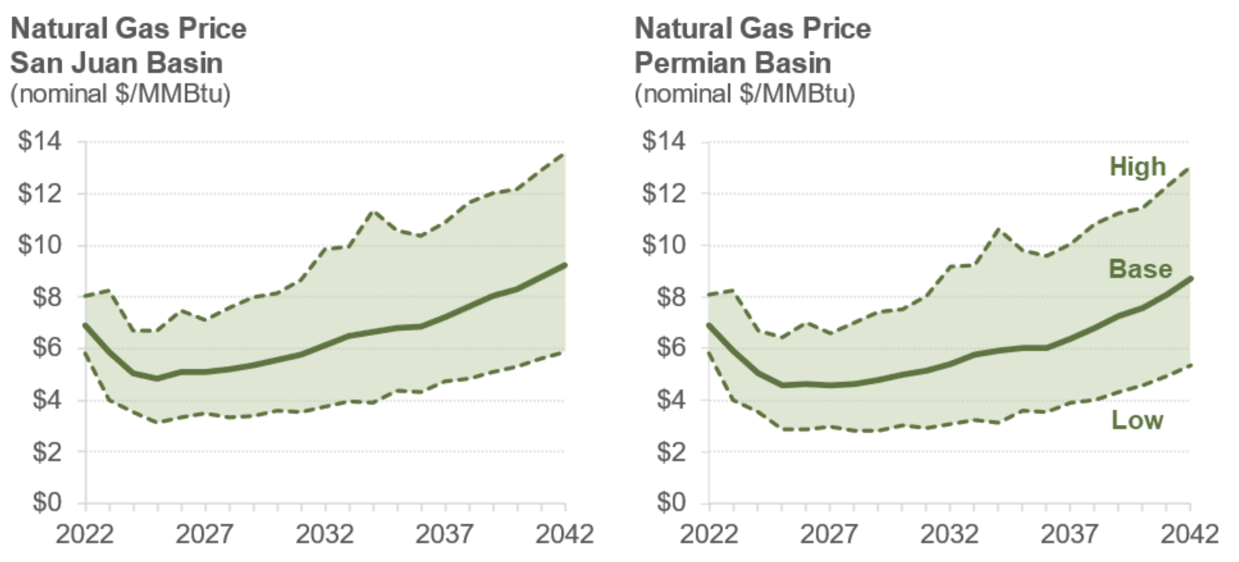
6.6 Commodity Price Forecasts

Historically, forecasted commodity costs have played a critical role in determination of the most cost-effective portfolio (MCEP) and longer-term planning. In this IRP, decisions around PNM's portfolio are primarily driven by emissions reduction and RPS targets, with commodity costs playing a smaller role. Still, the cost implications of these decisions are impacted by the expected prices for natural gas, hydrogen fuel, and the wholesale electricity throughout the IRP timeframe. The comparison between these variable costs and the upfront costs of renewables and storage helps to determine the optimal resource selection to meet carbon reduction targets.

Natural Gas Prices

PNM's natural gas supplies are sourced from two production basins: the Permian Basin in Texas and the San Juan Basin in the Four Corners region. The plants in the southern part of New Mexico are typically supplied from the Permian Basin via the El Paso Natural Gas (EPNG) Southern Mainline; plants in the north can also be supplied from the San Juan Basin via either New Mexico Gas Company's system or by either the EPNG Northern Mainline or the Transwestern Pipeline. Forecasts for natural gas commodity prices in each of these supply basins were developed by Siemens using fundamentals-based analysis of continental supply and demand for natural gas as well as forward prices up to February 2025. These forecasts are shown in Figure 60; supporting data is provided in Appendix G.

Figure 60. Natural gas commodity price forecasts



In addition to the commodity cost of natural gas, PNM pays additional fees and taxes to deliver natural gas from the supply basins to the burner tip of PNM's generators. These fees and taxes include fuel surcharges, pipeline usage and transportation charges, and local gross receipts taxes. While these specific costs vary by plant based on its location and the pipeline transporting the fuel, they generally add between $0.50 to $1.00/MMBtu in additional costs to deliver natural gas to generators.

Hydrogen Prices

One of the potential options to meet a portion of future planning reserve needs in a carbon emissions-free portfolio is to repurpose natural gas generation infrastructure to operate using a "drop-in" carbon-free fuel. Since the passage of the IRA, commercial interest in hydrogen as an energy carrier has grown considerably. The 45V tax credit for hydrogen production is expected to stimulate a nascent industry, and the Department of Energy (DOE) recently announced $7 billion in grant awards to seven proposed hydrogen hubs around the country. As the industry begins to gain momentum, the prospect that some form of carbon-free fuel – hydrogen, renewable natural gas, or other synthetic fuels – may be available by 2040 is increasingly promising.

In the context of PNM's 100% goal, these fuels are appealing for numerous reasons: first, they would continue operations of some existing natural gas generation infrastructure beyond the 2042 time frame, allowing PNM to recover the costs of investments over a longer economic lifetime and thereby mitigating costs to customers; and second, they would provide an option for a firm, carbon-free resource, a crucial cornerstone of a reliable carbon-free portfolio. Present expectations suggest that these fuels would likely be costly to produce, deliver, and store; nonetheless, PNM would expect to use them infrequently and in small quantities much like peaking plants today.

While these types of options would provide significant value to PNM's customers in the context of its 100% goal, the price at which these fuels may be offered in the future is a significant uncertainty. While many of the technologies needed to create these fuels exist today, the supply chains to produce and deliver these fuels at scale do not. Whether and at what scale these types of fuels are available will have particularly significant ramifications upon the nature of the challenges as PNM's portfolio approaches 100% carbon emissions-free energy. This IRP assumes a hydrogen fuel cost in 2040 of $32/MMBtu, a price intended to reflect the all-in cost of production, storage, and delivery of hydrogen beyond the horizon of incentives offered by the IRA. Additional detail is provided in Appendix G.

Carbon Prices

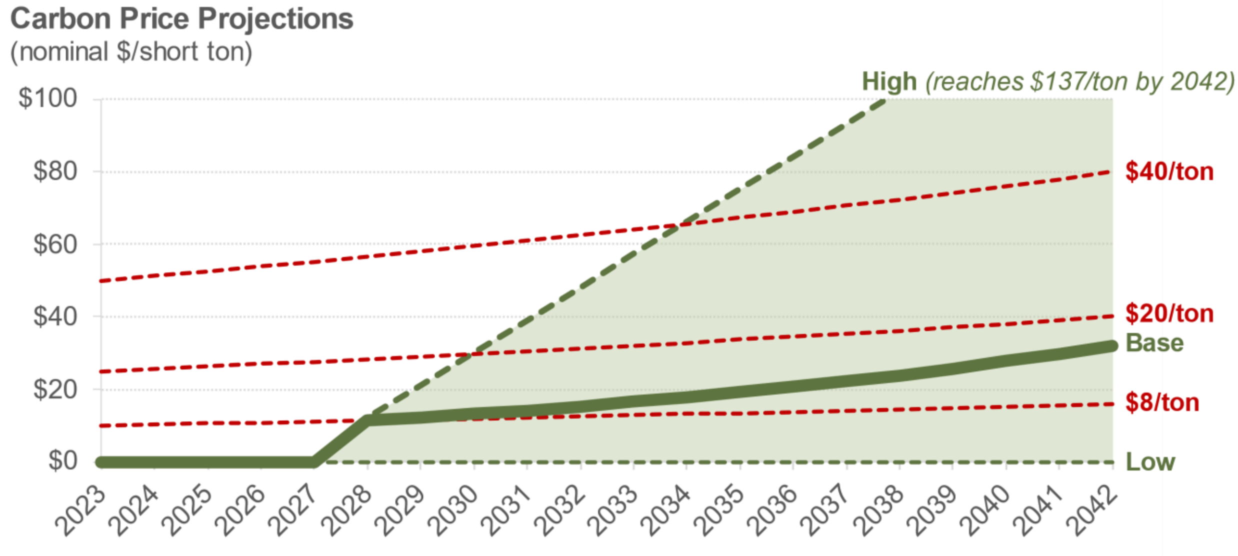
This IRP analysis considers three forecasts of future carbon pricing derived from scenarios originally developed by Siemens. The lowest carbon price projection assumes no state or federal carbon pricing regimes throughout the planning period. In the "Base" case, carbon pricing begins in 2028 at $11/ton and escalates over the planning period to $32/ton; in the "High" case, carbon pricing begins in 2028 at a similar level but escalates at a higher rate to reach $132/ton by 2042.[44]

In addition to these scenarios, This IRP analysis also considers the range of carbon pricing as required by the final order in Case No. 06-00448-UT. This order requires regulated utilities to provide portfolio cost estimates using CO2 emission prices of $8, $20, and $40 per metric ton (starting price in 2010 dollars, escalating at 2.5% per annum).

The full range of carbon pricing scenarios analyzed in the IRP is shown in

Figure 61.

Figure 61. Carbon price projections used in IRP analysis[45]



[44] In the "Base" and "High" carbon pricing scenarios provided by Siemens, carbon pricing commences in 2025. For the IRP, this starting point is adjusted to 2028, reflecting a view that implementation of a meaningful carbon pricing signal in the next two years is an unlikely possibility.

[45] Reference and High price trajectories for carbon shown here reflect values modeled in EnCompass. These prices were not escalated for inflation. However, because of the significant impacts of clean energy targets and the corresponding low carbon intensity of all portfolios, carbon prices are shown through sensitivity analysis not to significantly impact portfolio decisions or relative portfolio costs. For additional discussion of impact of carbon prices on results, see Figure 85 in Section 7.3.7.2. Both the "modeled" and "adjusted" price forecasts are reported in Appendix G.

Wholesale Electricity Market Prices

To capture the dynamics of PNM's interactions with the broader region within its planning process, this analysis incorporates projected wholesale market prices at the Palo Verde and Four Corners market hubs. These forecasts are also developed by PACE Global using a fundamentals-based model of the Western electricity system and reflect the same future commodity price forecasts for natural gas as PNM uses in its own analysis.

The wholesale market price projections used in this analysis are shaped on an hourly basis and reflect an expectation that continued investments in solar generation throughout the Western Interconnection will increasingly result in the lowest prices in wholesale markets during the daytime hours and the highest prices during the evening hours of sundown (exhibiting the same general shape as California's eponymous duck curve). Figure 63 shows the evolution of these patterns over the twenty-year analysis horizon as captured in the forecast provided by PACE Global, in which the effects of solar saturation on daytime prices become increasingly pronounced.

Figure 62. Wholesale market price projections used in IRP analysis

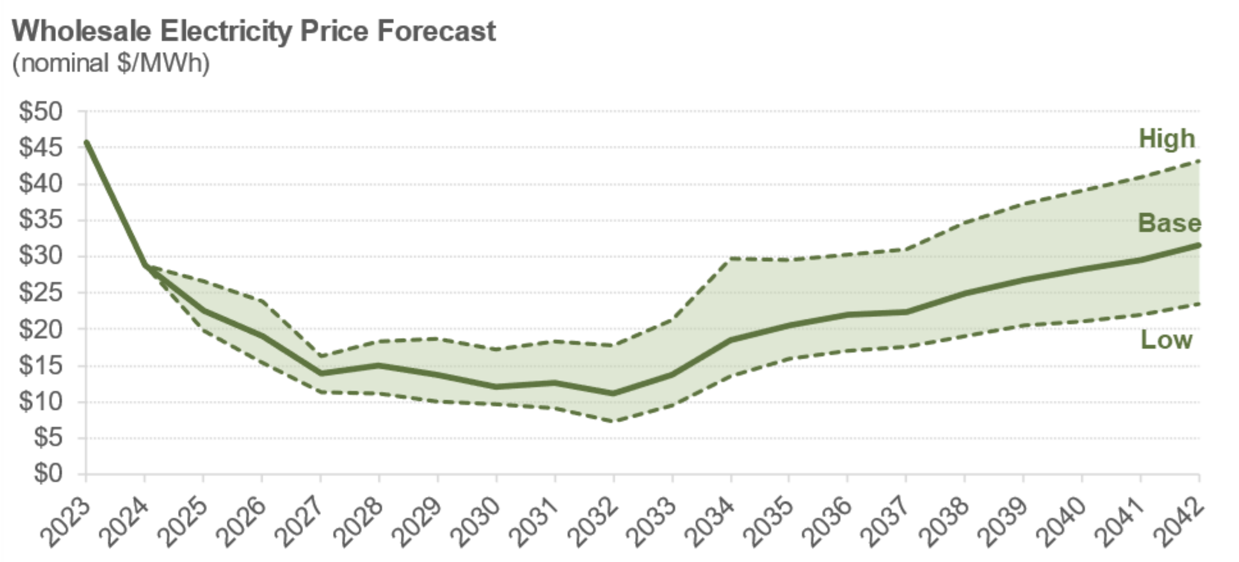
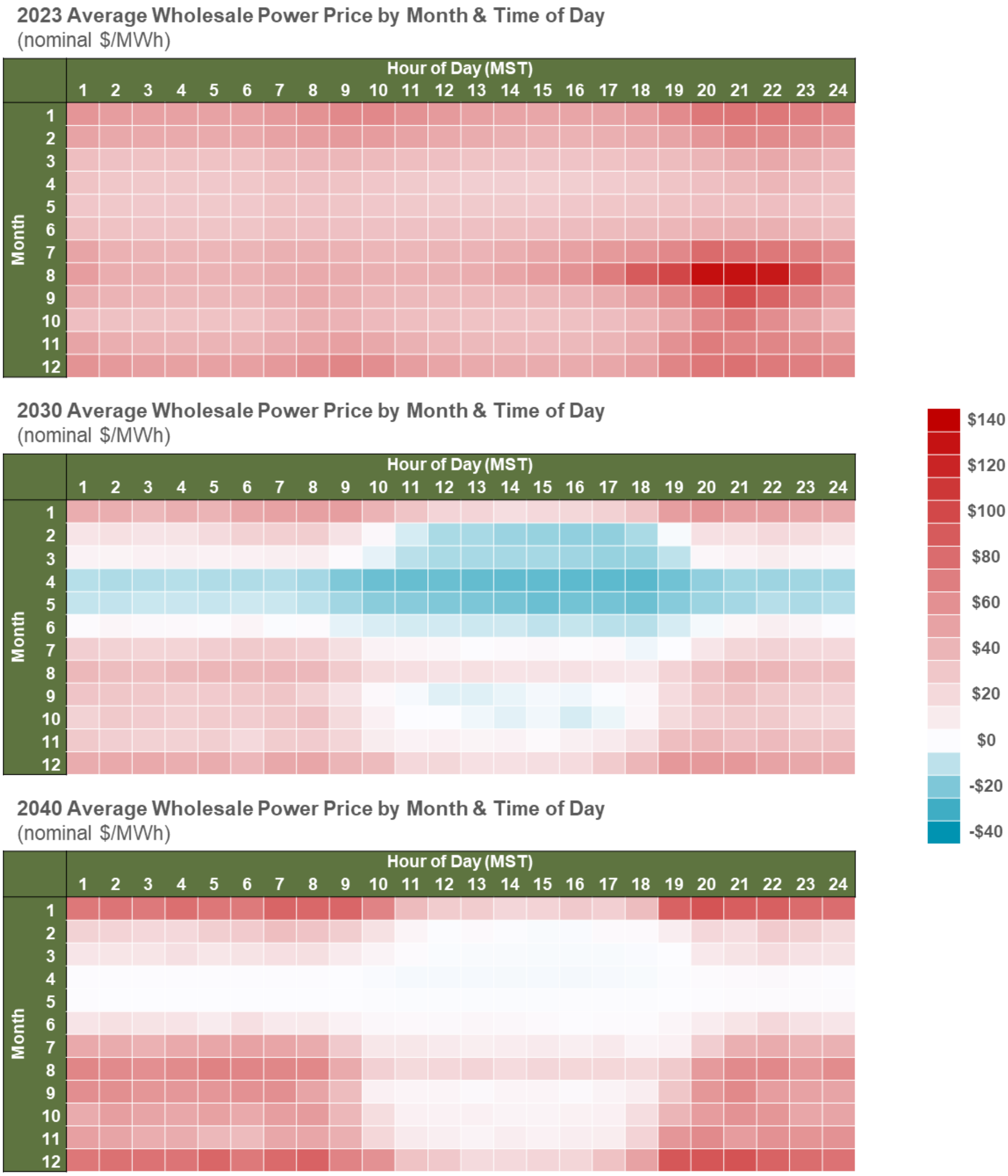


Figure 63. Changes in wholesale market pricing dynamics incorporated in IRP analysis



7 Portfolio Analysis

Chapter Highlights

- This IRP analysis identifies multiple plausible plans to achieve the transition to a carbon-free portfolio by 2040 while preserving reliability. All portfolios will require PNM to make significant investments in wind, solar, storage, and demand-side resources; portfolios with fewer technology restrictions also include hydrogen-ready combustion turbines and long-duration storage resources for resource adequacy. All these potential plans meet the requirements of the ETA.
- The way PNM's system operates will change dramatically under all cases: whereas today's system relies predominantly on the load-following capabilities of coal and gas resources to balance load, in the future, PNM will rely on storage, flexible gas, and renewable curtailment to manage "net load" dynamically.
- As PNM transitions to higher penetrations of renewables, the most challenging periods for maintaining reliability will shift from the afternoon peak period to the evening after sunset. Firm resources that can provide stable and sustained output during non-daylight hours are essential to maintaining resource adequacy under these conditions.
- Scenarios that impose restrictions upon the types of resources available to PNM as options to meet future needs generally result in higher costs to customers; this finding holds true across a wide range of futures and sensitivities.
- In contrast, scenarios that include a broad range of options tend to yield lower costs and provide means to mitigate many of the risks and uncertainties that PNM faces. After exhaustive analysis of many scenarios, PNM finds that the "All Technologies" scenario that follows this approach – which incorporates renewables, short- and long-duration storage, demand side programs, and hydrogen-ready thermal resources – is best suited for PNM's MCEP in this IRP.

This section reviews the model results for the analysis framework described in Section 5.1. This section starts with an overview of portfolio results that outlines for each scenario the installed capacity, cost, carbon emissions, resource adequacy, and typical hourly operations. Following this, a discussion is presented on uncertainty and risk in the portfolios through analysis of different futures and sensitivities, as well as through qualitative discussion of key hard-to-quantify factors. The final part of this section provides results of additional portfolios that fall outside the main analysis framework. These portfolios are a combination of suggestions from stakeholders, analyses done to answer specific but tangential questions, and early tests of new model functionality that might be brought into future IRP models.

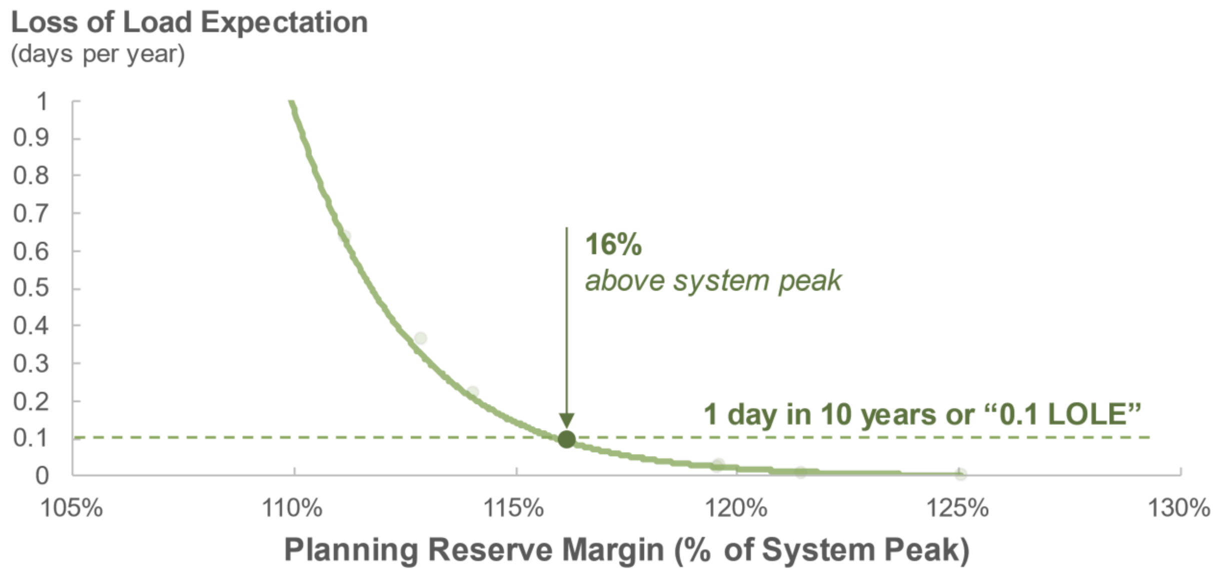
7.1 Capacity Needs

The first key analytical step in the portfolio analysis process is an assessment of capacity needs using loss-of-load-probability modeling. To ensure resource adequacy, each portfolio built is tested against a target reliability standard of **1-day-in-10-year loss of load expectation, or 0.1 days per year**. Using SERVM to identify a PRM requirement and calculate ELCC curves for various technologies allows the long-term capacity expansion model to develop portfolios that meet this standard.

7.1.1 Planning Reserve Margin

To reflect this reliability standard in capacity expansion modeling, the reliability standard is translated to a target planning reserve margin (PRM), which approximates the margin above system peak needed to meet the LOLE standard of 0.1 days per year. Figure 64 shows the illustrative relationship between planning reserve margin and the resulting level of reliability (lower levels of planning reserves translate to higher frequency of loss of load).

Figure 64. Relationship between LOLE and Planning Reserve Margin

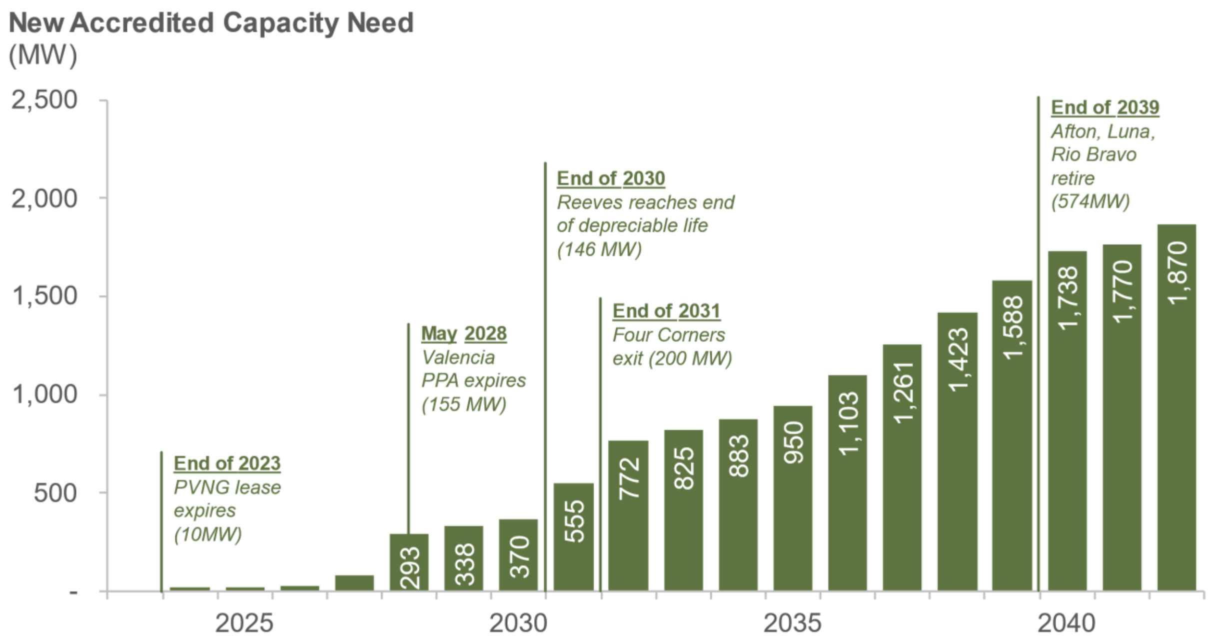


In this IRP, a **16% target planning reserve margin** (target PRM) is sufficient to approximate the LOLE standard of 0.1 days per year. Applying this target PRM ensures capacity expansion modeling builds sufficient resources in each year to meet this standard. Because 16% is an approximation, for the final portfolio analysis, select portfolios created in Encompass are ultimately tested in SERVM to evaluate whether they adhere to the 0.1 days per year standard in 2032 and 2040. Any portfolios that deviate from this standard by a significant margin are subsequently adjusted to improve alignment with this standard. More details about the methodology can be found in Section 5.2.

7.1.2 Existing Resources

Existing and planned resources, summarized in Table 50, are sufficient to meet most of PNM's near-term capacity needs. Beginning in 2028, a larger capacity need arises due to load growth and continued changes to the resource portfolio: (1) in 2028, the Valencia PPA expires; (2) in mid-2031, PNM plans to exit FCPP when the current the operating agreement expires; and (3) at the end of 2031, Reeves reaches the end of its depreciable life. Thereafter, capacity needs grow with load growth. Towards the end of the 2030s, additional natural gas units will be retired to continue the transition to a carbon-free system, so long as the remaining resources in the portfolio can meet reliability needs. This growing capacity need is summarized in Figure 65.

Figure 65. PNM's growing capacity need for new capacity over time



Today, most of the reliability needs are met with thermal resources, like gas and nuclear. As new low-cost carbon-free and energy-limited resources are added, like solar and storage, their share of the total contribution to system reliability will increase. Table 50 shows the supply- and demand-side resources and their capacity contribution to the system.

Table 50. Loads and resources, existing resources only

Description	Notes	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Forecasted System Peak	**(1)**	**2,066**	**2,110**	**2,191**	**2,249**	**2,276**	**2,323**	**2,359**	**2,387**	**2,424**	**2,472**	**2,488**	**2,535**	**2,575**	**2,592**	**2,630**	**2,658**	**2,704**	**2,737**	**2,765**	**2,791**
EUEA Energy Efficiency		-28	-49	-65	-68	-68	-68	-66	-66	-66	-66	-36	-34	-34	-15	-15	-	-	-	-	-
Net System Peak	**(2)**	**2,038**	**2,061**	**2,125**	**2,181**	**2,208**	**2,255**	**2,294**	**2,321**	**2,358**	**2,407**	**2,452**	**2,501**	**2,541**	**2,577**	**2,614**	**2,658**	**2,704**	**2,737**	**2,765**	**2,791**
PRM Requirement	(3)	12%	12%	12%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
Total Requirement		**2,282**	**2,309**	**2,381**	**2,530**	**2,562**	**2,616**	**2,661**	**2,692**	**2,735**	**2,792**	**2,844**	**2,901**	**2,948**	**2,989**	**3,032**	**3,083**	**3,136**	**3,175**	**3,207**	**3,237**
Existing Resource (Accredited Capacity)																					
Nuclear	(4)	292	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282	282
Coal	(4)	160	160	160	160	160	160	160	160	160	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	(4) (6)	968	968	968	968	968	818	818	818	677	677	677	677	677	565	454	343	232	121	121	121
Geothermal	(4)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	-
Wind	(5)	132	132	132	132	132	132	132	132	132	132	132	132	112	112	112	112	112	112	112	50
Solar	(5)	46	86	85	107	106	105	105	104	104	103	103	102	102	101	98	98	97	97	96	93
Storage (4hr)	(5)	144	526	526	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820	820
Demand Response	(5)	23	23	23	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Short Term Contracts		508	105	172	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Resources		**2,278**	**2,287**	**2,354**	**2,497**	**2,474**	**2,323**	**2,323**	**2,322**	**2,180**	**2,020**	**2,019**	**2,019**	**1,998**	**1,886**	**1,772**	**1,660**	**1,549**	**1,437**	**1,437**	**1,437**
Capacity Surplus (Shortfall)		**-5**	**-21**	**-27**	**-33**	**-88**	**-293**	**-338**	**-370**	**-555**	**-772**	**-825**	**-883**	**-950**	**-1,103**	**-1,261**	**-1,423**	**-1,588**	**-1,738**	**-1,770**	**-1,870**

Notes

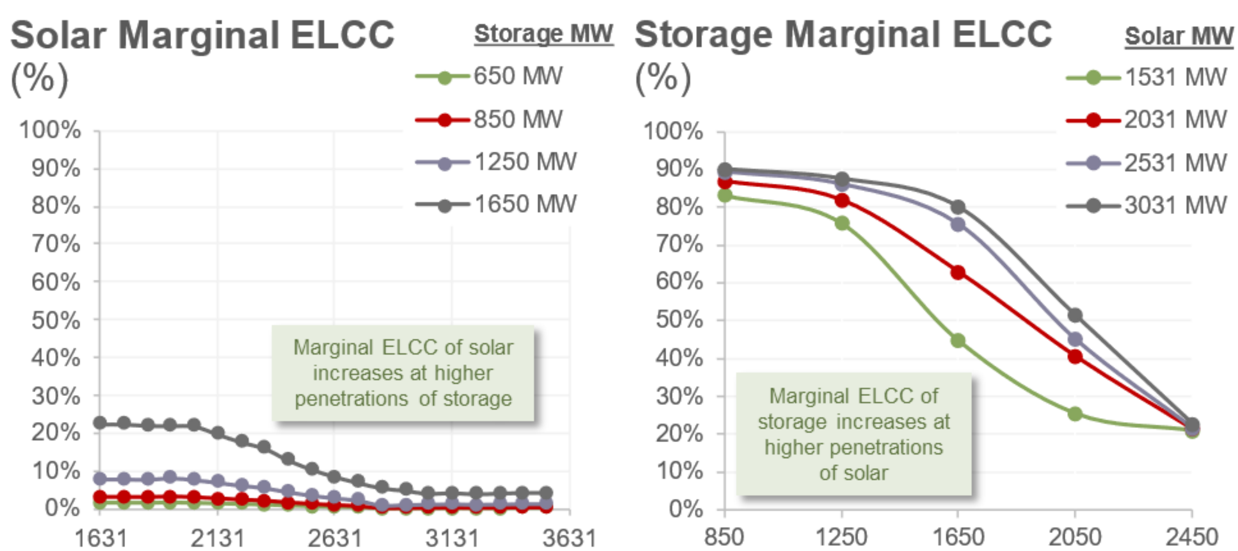
1. "Forecasted System Peak" does not include impacts of energy efficiency, which is shown below as a load adjustment
2. "Net System Peak" includes impacts of all load-modifying resources, including energy efficiency
3. For the years 2023-2025, a 12% PRM requirement is maintained; thereafter, the portfolio transitions to 16%.
4. Accredited capacity for firm resources (nuclear, coal, and natural gas) reported using "Unforced Capacity" (UCAP) convention
5. Accredited capacity for non-firm resources (renewables, storage) reported using "Effective Load Carrying Capability" (ELCC) convention
6. Firm capacity from natural gas units retiring by 2040 declines over four years to allow gradual transition to carbon-free portfolio. In certain scenarios, some units may be converted to hydrogen

7.1.3 Effective Load Carrying Capability of New Resources

To determine each resource type's ability to meet this capacity need, PNM uses the effective load carrying capability (ELCC) methodology. The advantage of the ELCC methodology is its ability to capture the changing reliability needs of the system as the portfolio evolves, which is represented by technology-specific ELCC curves. Following sections discuss the contribution to reliability for each resource type. Additional details about the ELCC methodology can be found in Section 5.2.1.

As in prior IRPs, ELCC curves are used to capture the capacity contributions of different resources as their penetration changes. One of the added complexities considered in this IRP is how changes in the penetration of one type of resource will impact the marginal ELCC of another. These are often described as "interactive effects," and are an important dynamic to consider in optimizing for reliability. For instance, as other studies have also found, the presence of larger penetrations of solar resources will tend to result in higher marginal ELCCs for energy storage, and vice versa. Examples of how these two technologies interact are shown in Figure 66, which illustrates outputs from the SERVM model for PNM's system.

Figure 66. Marginal ELCC curves for incremental solar and storage resources



EnCompass' ability to capture the multidimensional relationships between different technologies that are implied by the figures above is limited, as the ELCC curves input into the capacity expansion model must be specified independently. At the same time, the importance of these interactive effects between different technologies in their contributions to resource adequacy. To best capture these dynamics in the development of the portfolio, ELCC curves are modeled for solar and storage that adjust over time based on *assumed* changes to the rest of the portfolio. For instance, for energy storage, three different ELCC curves are used in the analysis:

- Between 2023 and 2031, the storage ELCC curve reflects a system with approximately 1,500 MW of solar.

- Between 2032-2039, the storage ELCC curve is adjusted to reflect a system with 2,000 MW of solar. This is generally consistent with the levels of solar penetration observed in the 2020 IRP as well as initial testing runs conducted for this IRP.
- Between 2040-2042, the storage ELCC curve reflects a system with approximately 2,500 MW of solar. As above, this level of penetration is generally consistent with both the 2020 IRP portfolios and initial tests in this IRP.

A similar approach is used to characterize the marginal ELCC of solar as well. The specific curves applied to storage and solar are shown in Table 51 and Table 52, respectively. Because wind resources do not exhibit the same degree of interactivity with solar and energy storage, a single ELCC curve is applied to new wind resources throughout the horizon. This is shown in Table 53.

Table 51. ELCC curves applied to storage in EnCompass

Storage Capacity (MW)	Effective Load Carrying Capability (%)		
	2023-2031	2032-2039	2040-2042
850	*85%*	*64%*	*53%*
1,050	81%	*64%*	*53%*
1,250	76%	*64%*	*53%*
1,450	65%	*64%*	*53%*
1,650	45%	62%	*53%*
1,850	28%	50%	*53%*
2,000	25%	40%	*53%*
2,500	24%	33%	36%

Table 52. ELCC curves applied to utility-scale solar in EnCompass

Solar PV Capacity (MW)	Effective Load Carrying Capability (%)		
	2023-2031	2032-2039	2040-2042
1,500	6%	*19%*	*24%*
2,000	2%	15%	*24%*
2,500	1%	14%	15%
3,000	0%	8%	7%
3,500	0%	1%	2%
4,000	0%	0%	0%

Table 53. ELCC curve applied to wind in EnCompass

Wind Capacity (MW)	ELCC (%)
	2023-2042
600	20%
800	19%
1,000	12%
1,200	7%
1,400	1%

Unlike renewables and storage resources, firm generating resources produce electricity on-demand, a desirable characteristic for reliability. However, existing technologies in this category typically use fossil fuels to produce electricity, thus emitting carbon dioxide and other greenhouse gas emissions. In a deeply decarbonized future, these resources may run sparingly, only to avoid period of renewable output droughts from low-cost carbon-free resources and lack of energy stored in dynamic balancing resources. Until a non-carbon emitting firm generating technology is mature enough to reliably contribute to electricity systems, i.e., higher levels of ELCC, traditional firm generating resources continue to play an important role in maintaining resource adequacy.

Firm generating resources are accredited using an Unforced Capacity (UCAP) rating. This represents each technology's expected availability throughout the year, less a derate for the probability of unplanned outages. For example, a 100 MW natural gas CT with a 96% rating would contribute 96 MW of accredited capacity to the total capacity need.

Table 54. Unforced capacity derates applied to existing firm generating resources

Firm Generating Resource Type	Unforced Capacity Rating
Nuclear	98%
Coal	80%
Gas CCGT	98%
Gas CT	96%
Gas ST	97%

7.2 Portfolio Screening Analysis (Phases 1 & 2)

To identify the most suitable mix of resources for the Most Cost-Effective Portfolio (MCEP), portfolios are screened based on its performance across three main phases. In Phases 1 and 2, PNM explores a wide range of potential resource portfolios to characterize how different technologies (and combinations thereof) can meet PNM's future needs. These cases serve as a screening analysis that informs the selection of six specific portfolios for additional study in Phase 3. Section 5.2 describes the screening analysis in further detail.

7.2.1 Summary of Results

To perform the screening analysis, Encompass, PNM's IRP capacity expansion model, is used to construct an optimal portfolio based on the specific resource constraints in each scenario. To evaluate each scenario's performance, three main outputs are used to assess scenario performance:

1. Present value revenue requirement (measured in $ millions);
2. Present value of greenhouse gas emissions (measured in million tons);[46]
3. Weighted average technology readiness level of new resources (as measured on a scale from 1, basic principles developed, through 9, commercially available and operational, developed by Sandia National Laboratory).

Additionally, all scenarios are simulated on an hourly basis under a single deterministic extreme weather year in EnCompass to ensure no major shortfalls in capacity needed to ensure reliability throughout the year. While this is not a substitute for a full loss of load probability study, it provides a rough indication that the resulting portfolios are reasonably reliable. All portfolios studied in Phases 1 & 2 exhibited low enough levels of unserved energy in this extreme weather test that lack of reliability did not manifest as a disqualifying concern for any single portfolio.

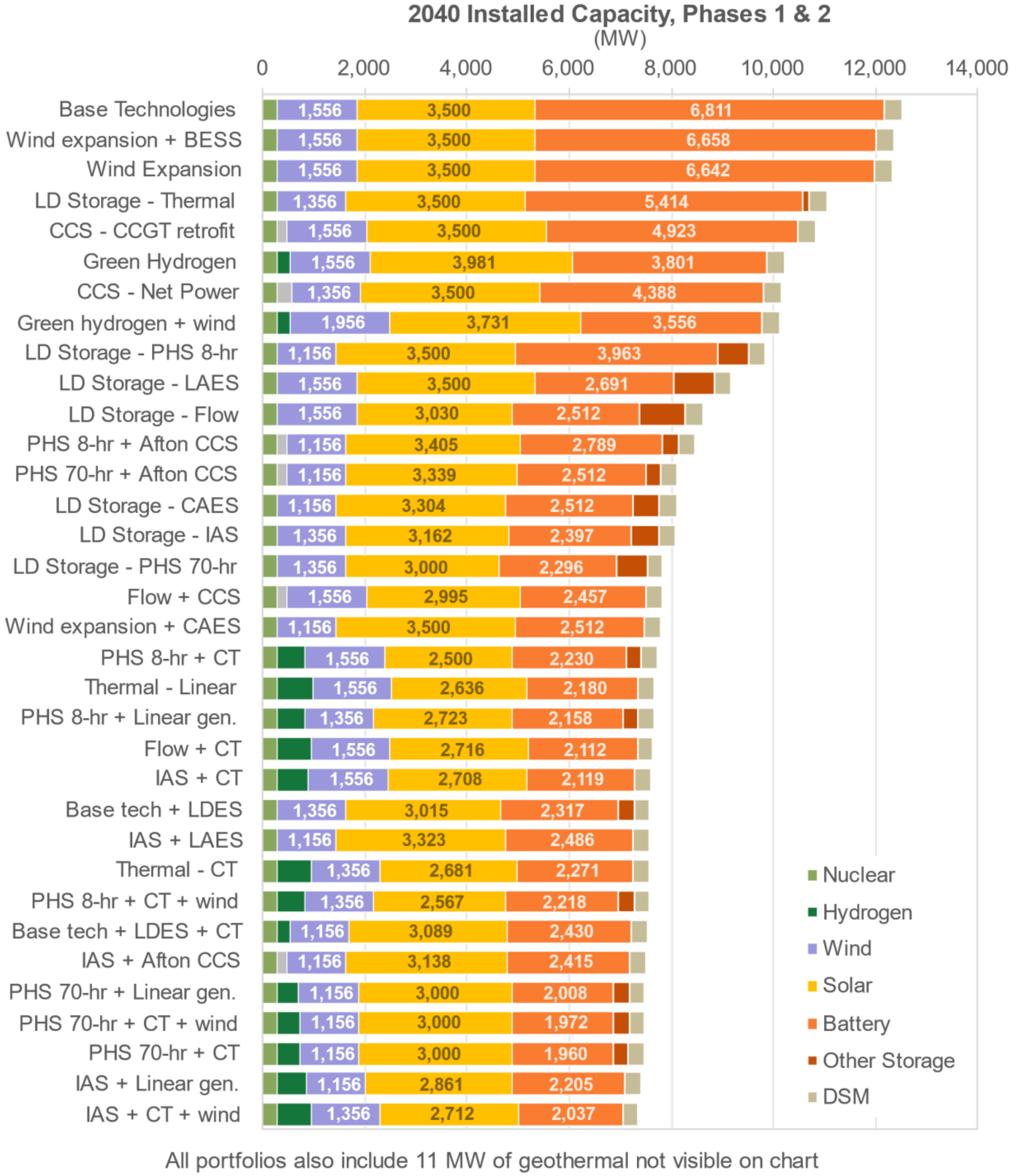
Table 55 shows the key metrics for each of the screening scenarios and Figure 67 shows a snapshot of the portfolio results from Encompass.

[46] Throughout this IRP, results for environmental metrics are based on model outputs from the capacity expansion analysis rather than the production cost analysis. Under the ETA, PNM is not required to attribute carbon emissions to short-term wholesale market purchases. Because wholesale market purchases are included in the production cost modeling, the resulting emissions attributed to PNM's portfolio may be understated depending on real-world conditions. By focusing on emissions outputs produced by the capacity expansion model, PNM ensures that the portfolios developed in the IRP are capable of meeting future requirements regardless of the availability of short-term wholesale market purchases, which is inherently uncertain.

Table 55. Key metrics for screening scenarios

Scenario Name	Total Installed Capacity, 2040 (MW)	Present Value Revenue Requirement ($ millions)	Present Value of Greenhouse Gas Emissions (million tons)	Weighted Average Technology Readiness Level of New Resources
Base technologies	12,522	$11,746	14.7	9.00
Wind expansion + BESS	12,367	$11,633	15.1	9.00
Wind expansion	12,353	$11,632	14.3	9.00
LD storage – Thermal	11,072	$10,862	14.3	8.95
CCS – CCGT retrofit	10,831	$11,203	15.6	8.98
Green hydrogen	10,222	$9,594	15.1	8.90
CCS – Net Power	10,166	$10,574	15.6	8.94
Green hydrogen + wind	10,125	$9,574	15.4	8.90
LD storage – PHS 8-hr	9,847	$10,505	15.6	9.00
LD storage – LAES	9,171	$10,753	16.0	8.87
LD storage – Flow	8,617	$10,490	15.4	8.90
PHS 8-hr + Afton CCS	8,472	$9,986	15.1	8.98
Flow + CCS	8,422	$10,363	15.3	8.91
Wind expansion + CAES	8,293	$9,916	14.7	8.98
IAS + LAES	8,144	$10,012	15.3	8.93
PHS 70-hr + Afton CCS	8,129	$10,009	15.6	8.98
LD storage – CAES	8,114	$10,317	14.9	8.98
LD storage – IAS	8,078	$9,979	15.2	8.93
Base tech + LDES + CT	7,927	$9,808	15.8	8.98
Base tech + LDES	7,889	$10,140	15.6	8.99
IAS + Afton CCS	7,885	$9,940	15.0	8.93
LD storage – PHS 70-hr	7,849	$10,388	15.3	9.00
Flow + CT	7,748	$9,669	16.2	8.99
PHS 8-hr + CT	7,726	$9,708	16.0	9.00
IAS + CT	7,703	$9,604	16.6	8.99
Thermal – Linear	7,673	$9,594	15.9	8.93
PHS 8-hr + Linear gen.	7,669	$9,688	16.0	8.95
Thermal – CT	7,581	$9,611	16.4	9.00
PHS 8-hr + CT + wind	7,580	$9,735	15.3	9.00
IAS + Linear gen.	7,503	$9,583	15.5	8.93
PHS 70-hr + Linear gen.	7,491	$9,845	15.5	8.96
PHS 70-hr + CT + wind	7,478	$9,826	15.5	9.00
PHS 70-hr + CT	7,474	$9,816	15.6	9.00
IAS + CT + wind	7,459	$9,579	15.5	8.99

Figure 67. Installed capacity in 2040 for each screening scenario



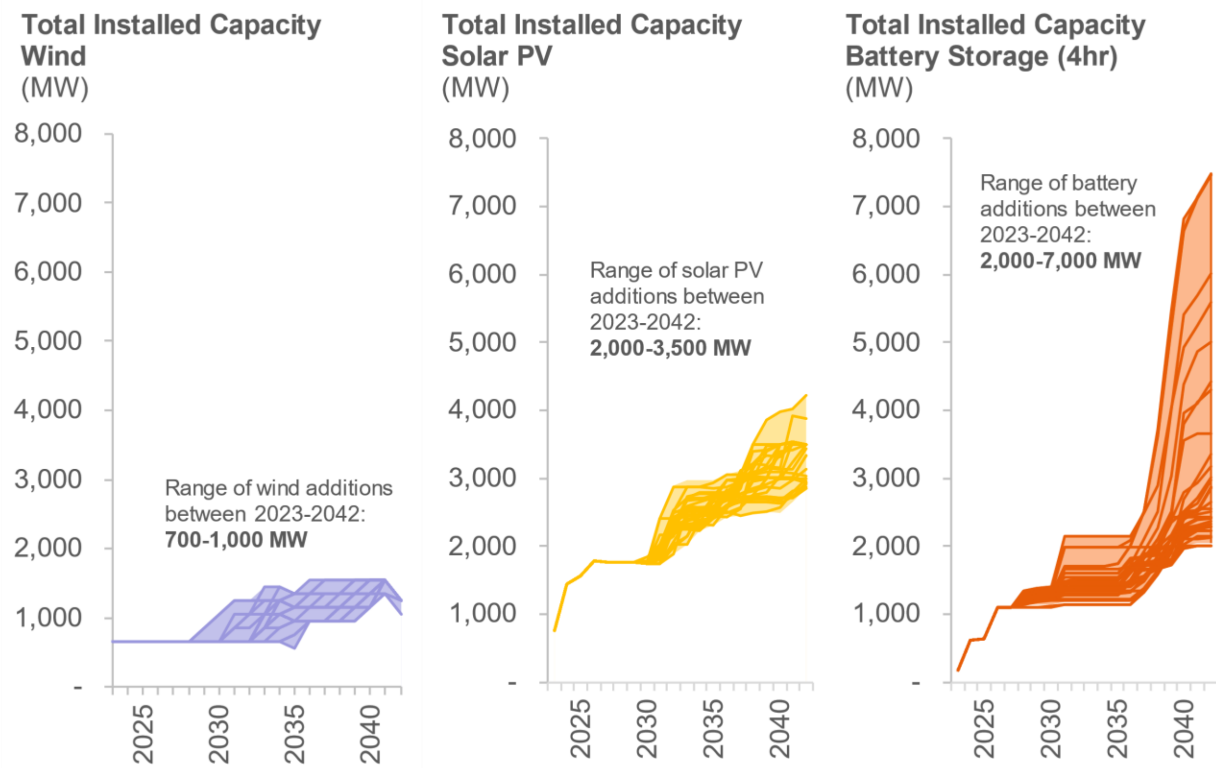
7.2.2 Findings from Phases 1 & 2 Analyses

Synthesizing the results across tested cases in the screening phase provides key insights that help shape an understanding of system needs and the opportunities to meet them:

1. **Every portfolio studied includes significant amounts of new wind, solar, and battery storage resources to advance progress towards PNM's 100% clean energy goals.**

As of 2023, PNM's annual energy generation includes 69% carbon-free resources and 31% from fossil fueled resources. Over the next seventeen years, the transition to a 100% carbon-free portfolio will require significant additional clean energy and balancing resources. Wind, solar and storage play a key role in fulfilling those needs across all scenarios studied in Phases 1 and 2, as indicated in Figure 68.

Figure 68. Ranges of total installed capacity for wind, solar, and storage resources across screening scenarios



A notable corollary to this finding is that PNM is poised to derive substantial benefits from the tax credits established by the IRA that these resources will like be eligible to receive.

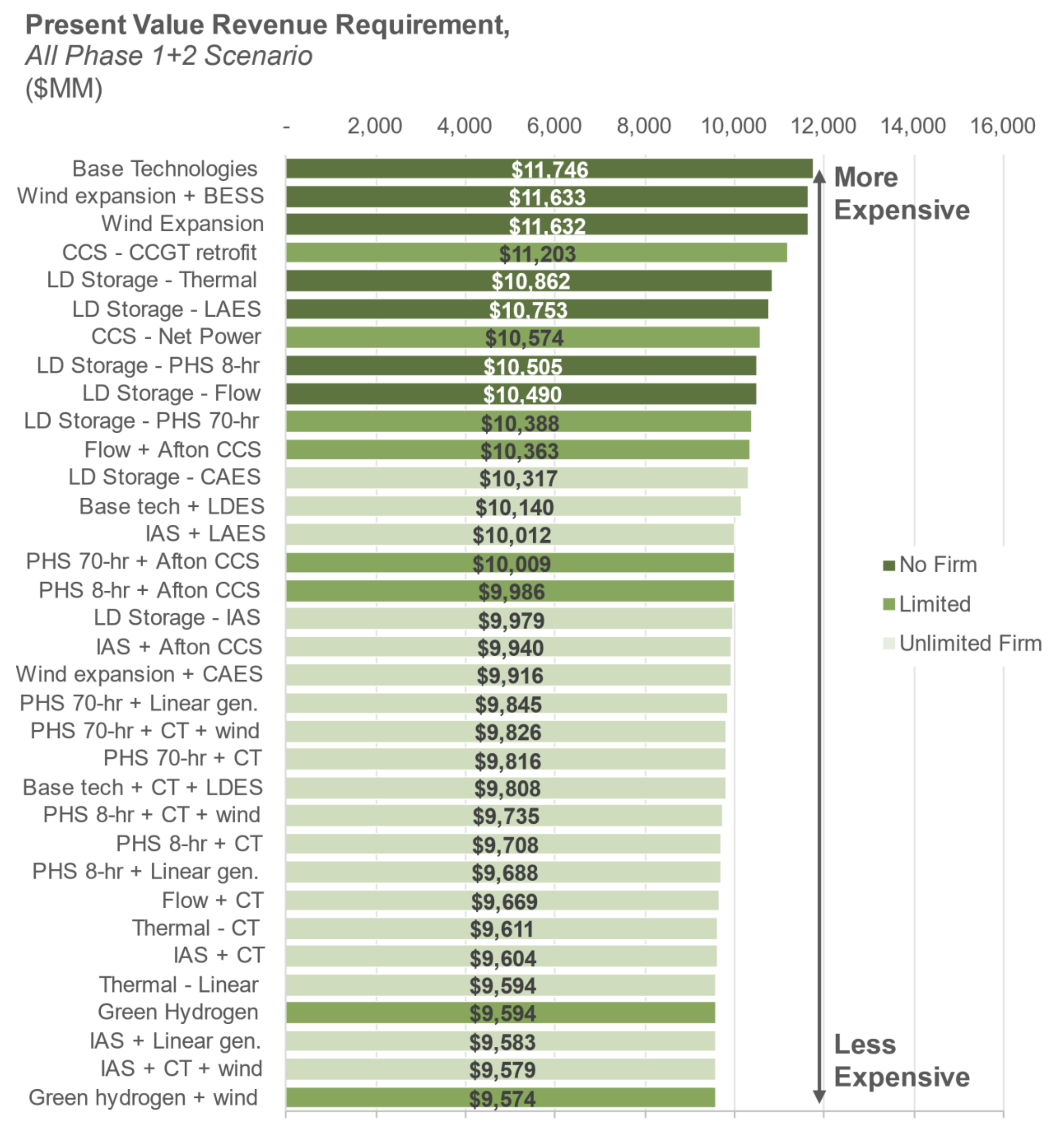
2. **A portfolio whose supply-side options are limited to *only* new wind, solar, and battery storage appears significantly more costly than alternatives that include firm resource options.**

Among the 34 different scenarios studied in Phase 1, seven prohibited all new firm resource options; eight allowed for prescribed (and limited) quantities of firm resources; and the remainder allowed for the model to select firm resources without an explicit limit. The contrast among these different scenarios provides an important insight for future planning efforts: that maintaining low costs will depend upon PNM's ability to deploy new firm resources at scale, predominantly because of their value to reliability. As summarized in Figure 68:

- The scenarios without any new firm resource options consistently exhibit *significantly* higher costs than other options evaluated.
- Scenarios with limited quantities of firm resources produce a wide range of cost outcomes, some of which are among the lowest cost scenarios studied.

- Scenarios with unlimited quantities of new firm resources available are generally among the lowest cost scenarios developed in Phases 1 and 2.

Figure 69. Present value revenue requirements across scenarios modeled in Phases 1 & 2 (classified by scenario-level treatment of firm resources)

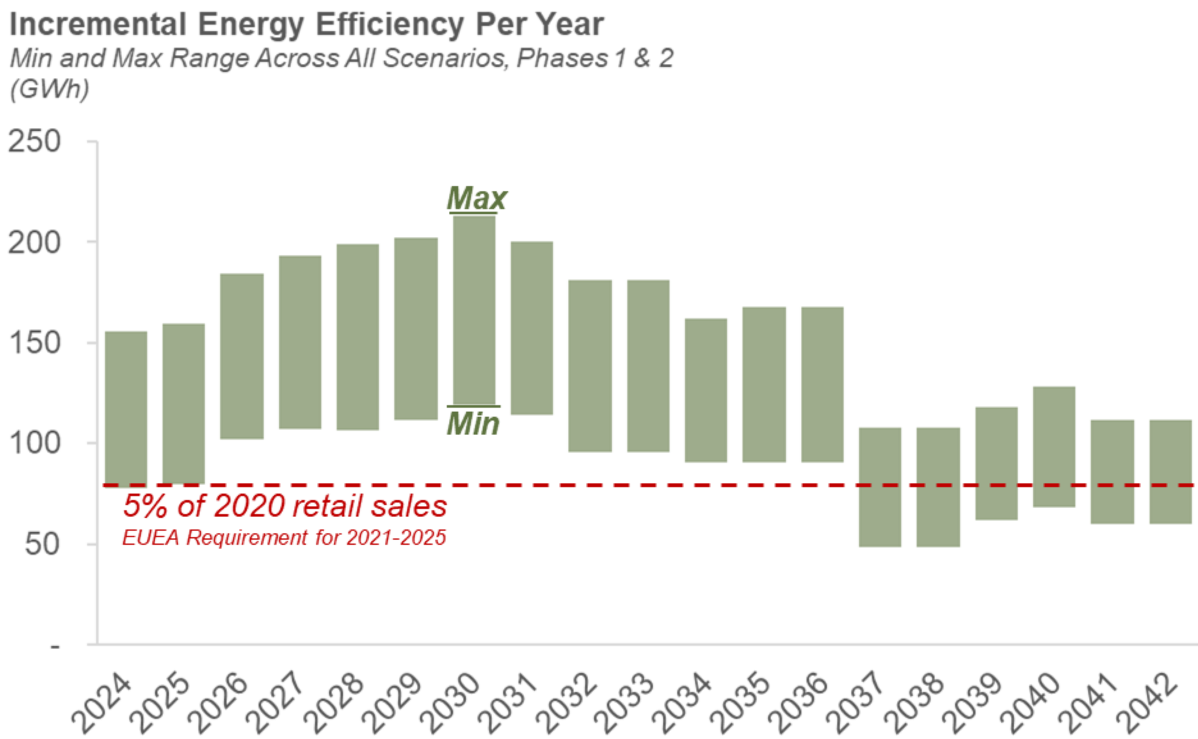


In this IRP, 24+hr storage resources (Iron-Air, Compressed-Air, and 70-hr Pumped Storage) are classified as “firm” resources

3. Demand-side resources will continue to complement supply-side options and play a crucial role in the transition to a carbon-free system.

Energy efficiency is modeled dynamically as a resource option in the IRP, allowing the capacity expansion model to select bundles of energy efficiency as part of a least-cost portfolio. Without exception, energy efficiency bundles are selected as part of a least-cost portfolio across all scenarios studied in Phases 1 and 2. While there is some variation in the quantities selected, the most common outcomes observed were that energy efficiency bundles at levelized costs up to $50-75/MWh were commonly selected, but bundles with costs above this level were rarely picked. Across all scenarios, the quantity of efficiency selected meets or exceeds the current EUEA requirements for the years 2021-2025 throughout most of the analysis horizon. This provides an important and useful informational data point for future customer program design.

Figure 70. Annual incremental energy efficiency savings selected across cases studied.



4. Among portfolios that include mature technologies only, a portfolio that includes wind, solar, and battery storage with complementary investments in new firm natural gas resources results in the lowest cost.

Of the portfolios developed and analyzed in the screening analysis, four relied exclusively on a mix of mature technologies that are commercially available today (a set that includes solar, wind, battery storage, pumped storage, and combustion turbines). These scenarios are:

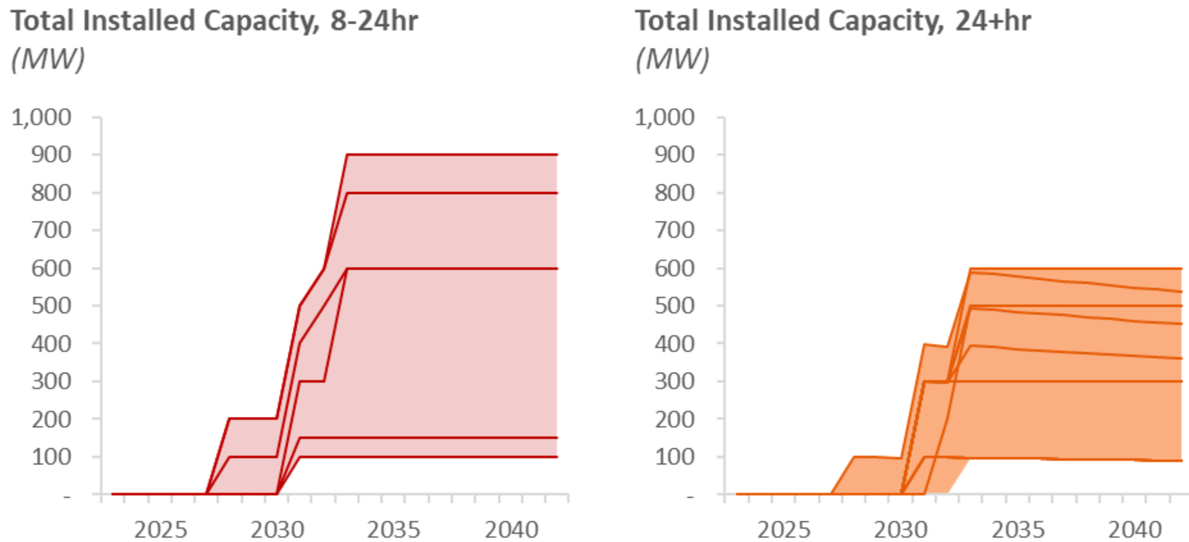
- Base Technologies (Wind, Solar, Battery Storage, and Demand-Side Resources Only)
- Base Technologies with rapid transmission deployment for wind resources
- Base Technologies with pumped hydro
- Base Technologies with hydrogen-ready combustion turbines

Among these four scenarios, the scenario with hydrogen-ready combustion turbines exhibits the lowest present value revenue requirement. The composition of this portfolio is similar in nature to the “Technology Neutral” scenario studied in the 2020 IRP, and the reasons for this portfolio’s relative cost advantage in this analysis remain consistent with the findings in that IRP. This portfolio balances the opportunity to integrate large quantities of relatively low-cost wind and solar resources with the need for new firm resources – satisfied in this case by natural gas combustion turbines – to ensure resource adequacy needs can be met even when variable renewables are unavailable due to meteorological conditions and storage resources have been fully exhausted.

5. A variety of long-duration storage technologies can serve as substitutes for firm natural gas resources; however, lack of technological maturity and corresponding cost uncertainties do not allow for definitive conclusions on their cost. When these solutions can be deployed will depend upon the rate of technological maturation and development timelines.

Portfolios tested in Phases 1 and 2 include a wide range of long-duration storage technologies (and combinations of those technologies). When compared against scenarios that allow for new investments in combustion turbines, the primary effect on the portfolio is that long-duration storage displaces investments in new natural gas resources. Figure 71 shows the difference in installed capacity between a subset of the long-duration storage scenarios and Base Technologies and Combustion Turbine in 2040.

Figure 71. Long-Duration Energy (8+hrs) Installed Capacity in Phases 1 & 2



6. A portfolio that includes combustion turbines fueled by hydrogen produced through electrolysis appears to be among the most attractive from a cost perspective due to IRA tax credits.

Due largely to the IRA's hydrogen tax credits, scenarios with hydrogen electrolysis results in increased federal tax benefits and reduces total system cost. In these scenarios, electricity generation for hydrogen fuel production and hydrogen electricity generation received production tax credits that lowered the total cost of the system below other scenarios.

In scenarios that include green hydrogen for electricity generation, the elements of hydrogen infrastructure provide benefits through the IRA investment or production tax credits. For production, benefits are associated with solar and wind resources; for storage, the benefits are associated with the investment in electrolysis infrastructure, and finally, for electricity generation from hydrogen electricity generation. Due to these tax benefits, the two Phase 1 and 2 scenarios that include hydrogen electrolysis beginning in 2031 result in the lowest and fourth-lowest cost portfolios.

While the Base Technologies and Electrolysis scenario is the least-cost pathway to meeting reliability and decarbonization goals, the technology and policy risks are high. To realize these benefits, rapid investments in electrolysis infrastructure, hydrogen storage and hydrogen-ready combustion turbines are needed before the next 7-10 years. To meet these, the already rapid increase of solar and wind resources would need to accelerate.

7. If transmission is available, the ability to integrate wind into the portfolio earlier reduces the costs of transitioning to 100% clean energy, regardless of what other resources are available in the portfolio.

New wind resources are selected in all portfolios examined in Phases 1 and 2. In most scenarios, 1,000 MW of new high-quality wind resources in Eastern New Mexico are selected – the maximum allowed due to assumed transmission constraints – indicating that a diverse portfolio of renewable resources that includes both solar and wind generation is important to PNM’s efforts to achieve a carbon-free portfolio.

In most scenarios studied in Phases 1 and 2, the IRP analysis assumes these resources cannot be developed prior to 2033 – this reflects an expectation of when the requisite transmission for delivery may be available due to long lead times associated with siting, permitting, and construction. However, a number of scenarios examine the impacts of altering this assumption, allowing new wind resources (and associated transmission) as early as 2028. Pairwise comparisons of cases with wind available in 2033 and wind available in 2028 (while all other aspects of the scenario are held constant) provide an indication of the value that accelerated procurement of wind would provide to PNM customers. The benefits of accelerating procurement of new wind, measured by the reduction in PVRR, range from $19 to $400 million depending on what other resource options are considered in the scenario. These comparisons are shown in Table 56.

Table 56. Select Cases with and Without Early Wind Expansion

Scenario	Net Present Value Revenue Requirement ($ millions)		
	Wind Available in 2028	Wind Available in 2033	Difference in PVRR
Base Technologies	$11,746	$11,632	$114
IAS + CT	$9,604	$9,579	$25
LD Storage – CAES	$10,317	$9,916	$402
Green Hydrogen	$9,594	$9,574	$20

While this benefit is present across all scenario pairings, it is relatively small compared to some of the other variations in cost among the scenarios. Nonetheless, the presence of new wind resources in all the Phase 1 portfolios, coupled with the long development timelines for new transmission projects, is indicative of the importance of actively pursuing resource diversity. Further, it implies that investment in supporting transmission infrastructure to access new high-quality wind in the eastern portion of the state is likely to be an important element of PNM’s strategy in the 2030s as well.

7.3 Final Portfolio Analysis (Phase 3)

The six scenarios described above are studied in an additional level of detail to inform the development of an MCEP. The scope of analysis conducted on these six scenarios includes:

- Development of portfolios using long-term capacity expansion modeling under the Current Trends & Policy future;
- Detailed resource adequacy studies using loss-of-load-probability modeling to quantify the performance of each portfolio in milestone years (2032, 2040) using a range of different metrics;
- A resilience analysis, in which a subset of the portfolios from the final phase are tested under several extreme weather case studies using parameters developed in the 2022 Resiliency in Planning for PNM study (included as Appendix N to this IRP);
- Development and analysis of portfolios under a range of alternative futures and sensitivities; and
- A qualitative discussion of additional risk factors considered in PNM's future resource plans.

These analyses allow for evaluation of a wide range of metrics that help better understand tradeoffs between cost, environmental impact, and reliability; with the express purpose of ultimately informing selection of the MCEP and the subsequent development of the Statement of Need and Action Plan.

7.3.1 Scenarios in Phase 3

The findings from the analysis in Phases 1 and 2, along with feedback and input provided by stakeholders during the facilitated stakeholder process, allowed PNM to narrow its focus by designing a smaller set of scenarios for subsequent analysis.

Scenario 1: Base Technologies Only ("Base Tech")

The first portfolio studied in the final stage of analysis is a portfolio that restricts future options for new resources considered to mature resources that do not rely on combustion technologies, a set that includes wind, solar, energy storage, and demand-side options. Despite its high cost in the screening phase, this portfolio provides a useful benchmark, and it also serves as a comparable reference to the "No New Combustion" scenario modeled in the 2020 IRP.[47]

Scenario 2: Base Technologies & Long-Duration Storage ("Base Tech + LDES")

Included at the request of stakeholders, this scenario considers long-duration storage technologies alongside wind, solar, battery storage, and demand-side measures. In this scenario, a wide variety of options for long-duration storage are included as options in the long-term capacity expansion, including pumped hydro storage, flow batteries, compressed air energy storage, thermal energy storage, liquid air energy storage, and iron-air energy storage. All long-duration storage resources are considered as options beginning in 2031. For pumped storage, this assumption reflects the relatively long lead time for permitting and development; for other technologies, this point in time reflects an assumption of when technologies that are not commercially available today may reach maturity on this timeframe.

[47] One key difference between the 2023 IRP's Base Technologies Only and the 2020 IRP's No New Combustion scenarios is that the latter did include options for longer duration (i.e., 8–10-hour storage), whereas in this IRP this scenario focuses on mature technologies present in the market today.

By allowing a diverse range of long-duration storage technologies to compete against one another in the optimization of a portfolio, the goal is not to identify a preference for a specific technology, but instead to allow for a broad enough range of options that help identify which characteristics (e.g. duration, efficiency) are of the most value to the portfolio.

Stakeholder Input: Long Duration Storage Scenario

During the facilitated stakeholder meetings, several stakeholders voiced a desire to study a scenario in which all long-duration storage technologies were included as resource options and allowed to compete with one another for selection in the portfolio. PNM agreed that this scenario merited further study and included it as part of the detailed Phase 3 scenario analysis as part of their request.

Scenario 3: Base Technologies & Hydrogen Ready Combustion Turbines ("Base Tech + CTs")

The third portfolio considered in the final stage is also a referent to one of the primary scenarios modeled in the 2020 IRP, the "Technology Neutral" portfolio. The results of the analysis conducted in Phases 1 and 2 indicate that a portfolio comprising wind, solar, storage, and hydrogen-ready CTs was the lowest cost portfolio among those reliant exclusively on mature technologies. Like the first scenario above, this scenario merits additional investigation because its reliance on currently mature technologies ensures identification of at least one possible plan that is low cost and feasible with technologies that are available today, even if none of the emerging technologies studied in this IRP reach commercial viability.

Scenario 4: Wind, Solar, Storage, Hydrogen-Ready Combustion Turbines, and Long-Duration Storage ("Base Tech + LDES + CTs")

In this stakeholder-requested scenario, PNM explored the role of firm generation alongside long-duration storage technologies. In this scenario, all the technologies from Scenarios 2 and 4 were available as candidate options in the long-term capacity expansion starting 2031. The goal of this scenario was to understand the economic tradeoff having both firm generators and long-duration storage technologies and to understand any combined benefits of having both in the system. Again, the goal was not to choose a specific technology but to identify the most valuable attributes of each technology.

Scenario 5: All Technology Options ("All Tech")

This scenario considered all resource options included in the previous five scenarios described above in the portfolio optimization.[48] One of the primary goals of the screening phase of this IRP was to test the functionality of the planning tools needed to model the wide variety of resource options. This scenario weighs the relative costs and benefits of all options against one another.

[48] One technology is excluded from this scenario: combustion turbines fueled by hydrogen produced via electrolysis as represented in Scenario 6. The initial screening phase indicated this to be a unique opportunity, both in terms of its cost impacts (due to federal tax credits offered by the IRA) and its technological readiness. These tradeoffs are explored in depth through Scenario 6 in the final phase, but due to the many risks and uncertainties associated with development of hydrogen production, storage, and combustion infrastructure, it was not considered in Scenario 5.

Scenario 6: Base Technologies & Hydrogen Electrolysis ("Base Tech + Electrolysis")

In this IRP, PNM also studies a variant on the 2020 Technology Neutral scenario in which new combustion turbines are fueled by hydrogen produced via electrolysis throughout their operational life (rather than converting to hydrogen fuel in 2040). The screening analysis in Phases 1 & 2 demonstrated that cases with hydrogen electrolysis were among the lowest cost scenarios evaluated, largely due to the presence of IRA tax credits. This scenario assessed how an earlier transition to hydrogen-fueled resources that leverages IRA tax credits could benefit customers and facilitate decarbonization.

Assumptions for the initial sizing of hydrogen infrastructure installed by 2032 are specified exogenously. The initial sizing of the combustion turbine, at 250 MW, is chosen to utilize a typical interconnection capacity at a hypothetical existing thermal site. The associated electrolysis facility is sized at 256 MW, which provides sufficient hydrogen production to 75-80% capacity factor. Because of its installation prior to the end of 2032, this facility is eligible for the PTC for each unit of hydrogen produced. In order to qualify for the full PTC under 45V, the carbon intensity associated with the production of hydrogen must be less than 0.45 kg CO2 per kg H2. Because of the uncertainty in how the US Treasury may implement a carbon accounting scheme to measure the carbon intensity of grid-connected hydrogen, the IRP conservatively assumes that the electrolysis load must be directly fueled by solar and/or wind generation.

Beyond 2032, additional hydrogen CT capacity is included as an option in EnCompass; however, this additional capacity must also be fueled by hydrogen produced by the same electrolysis facility. This option enables EnCompass to assess the role of further expansion of hydrogen-fueled generation infrastructure in contributing to PNM's resource adequacy needs.

Apart from these hydrogen-specific assumptions, all other resource options are modeled consistently with Scenario 1; that is, only wind, solar, storage, and demand-side resources are available for selection in the portfolio.

7.3.2 Portfolio Composition

Like in Phases 1 & 2, portfolios for each of the six scenarios studied in Phase 3 are developed using EnCompass for long-term capacity expansion. Unlike in Phases 1 & 2, portfolios in Phase 3 are subject to several additional reliability checks – and adjustment to the portfolio, if necessary – using SERVM to ensure alignment with the LOLE standard of 0.1 days per year. The result of this exercise is six carefully crafted portfolios that are well-aligned with both PNM's long-term goal of a carbon-free energy mix and its long-term reliability needs.

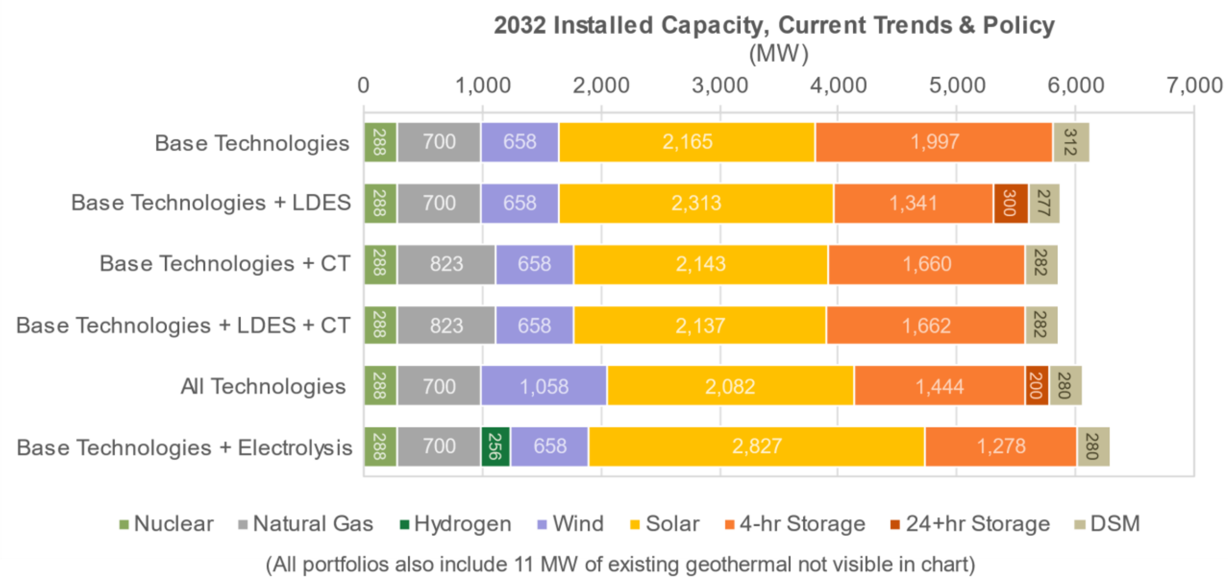
Capacity Mix

Figure 72 and Figure 73 show comparisons of the six portfolios at two key future milestones: (1) 2032, after the exit from FCPP and the end of the Reeves' depreciable life; and (2) 2040, upon the final transition to a carbon-free energy mix. By 2032, carbon-free generation resources make up 56-62% of the total nameplate capacity in the portfolio, achieving 83-94% reduction of carbon emissions relative to today's portfolio. Across the scenarios, the portfolio compositions are similar, but have slight differences in specific resource types.

- All portfolios include incremental additions of solar and four-hour storage resources, a complementary pairing due to the ability of energy storage to shift daytime solar production into the evening and nighttime hours.
- All portfolios include incremental DSM bundles, reaffirming the importance of customer programs as both a strategy to manage peak and provide clean "energy" to the system.

- The only scenario in which wind was considered as an eligible technology prior to 2033 (All Technologies) does include incremental wind resources in the 2032 portfolio, further evidence of the potential importance of resource diversity.
- Multiple scenarios include long-duration (24+ hour) storage resource additions (on the order of 200-300 MW) that contribute to meeting the need for capacity due to plant retirements and displace some shorter-duration storage resources.
- The Base Technologies + Electrolysis portfolio includes the *most* solar and the *least* four-hour storage across all portfolios; in this scenario, the solar not only helps serve loads but fuels electrolysis to produce hydrogen, which in turn fuels new combustion turbines whose flexibility and firm attributes displace the need for some four-hour storage.

Figure 72. Total installed capacity across scenarios in 2032 – Current Trends & Policy

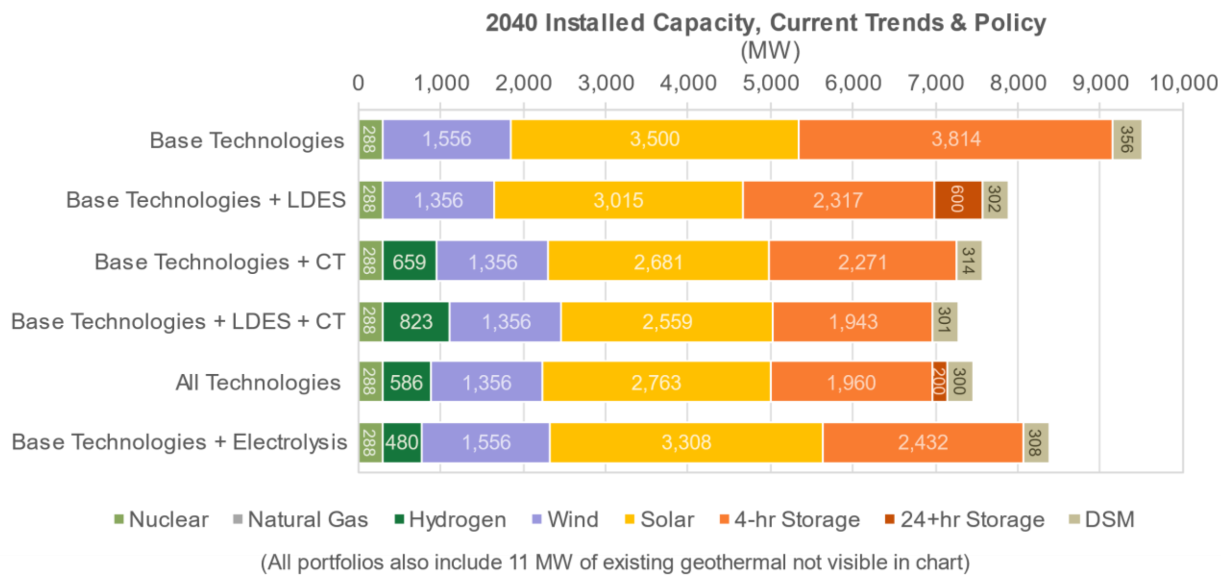


By 2040, the six portfolios diverge more significantly as they follow different pathways to meet PNM's carbon-free goal:

- While all portfolios include incremental solar, wind, storage, and DSM, the capacity additions are significantly higher in the Base Technologies scenario than in all others. These results reflect the challenge of meeting a stringent reliability standard with a limited set of options and few firm resources.
- The Base Technologies + LDES scenario becomes heavily reliant upon long-duration storage for reliability purposes. Whereas all other scenarios meet a portion of the need for firm resources with hydrogen-fueled combustion turbines, this scenario meets that need with 600 MW of new long-duration storage (as well as PNM's share of PVGS, common across all scenarios).
- The Base Technologies + CT, Base Technologies + LDES + CT, and All Technologies scenarios yield relatively similar resource mixes. All include hydrogen-ready combustion turbines to meet a portion of the need for firm resources.

- While the overall resource mix of the Base Technologies + Hydrogen Electrolysis scenario is also comparable to these three, it includes incremental quantities of solar resources necessary to supply the electrolysis loads to produce hydrogen.

Figure 73. Total installed capacity across scenarios in 2040 – Current Trends & Policy

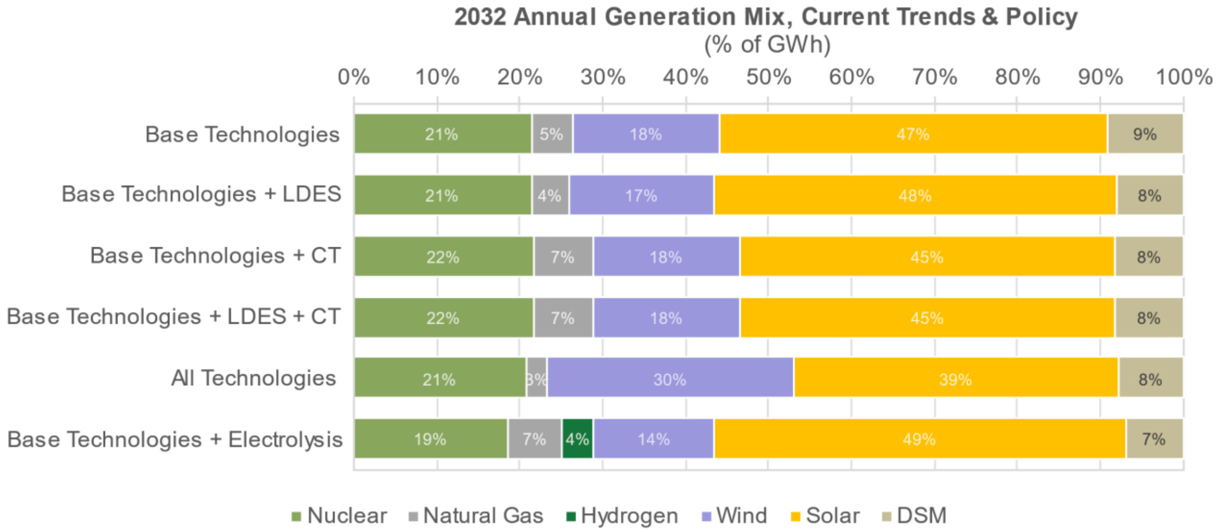


Energy Mix

Figure 74 and Figure 75 show the annual energy mix of the six different portfolios at the same two milestones at time. While the mix varies across the six scenarios, by 2032, all have generation mixes that exceed 90% carbon-free resources – a mix of nuclear, wind, solar, and demand-side resources – while the remaining share of approximately 5-10% is met by natural gas. Variations between scenarios are relatively minor, but several are notable:

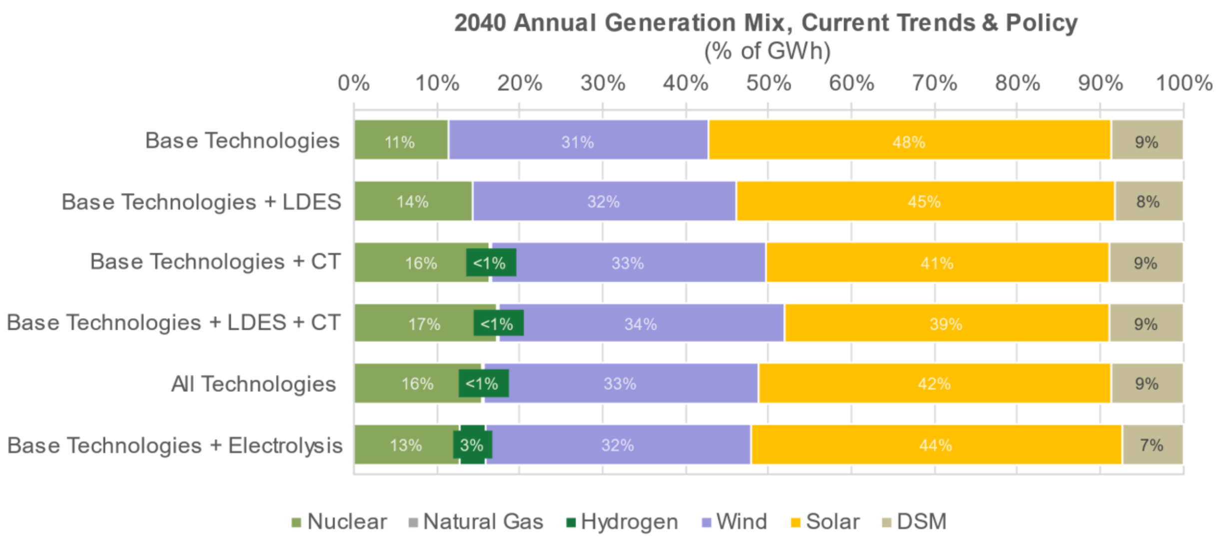
- The All Technologies scenario relies more heavily on wind than the other scenarios, enabled by the accelerated availability of complementary transmission. The additional wind resources predominantly displace solar generation as a source of carbon-free energy.
- The Base Technologies + Electrolysis scenario relies more heavily on solar resources than other scenarios, reflecting the additional solar energy used to fuel electrolytic hydrogen production. In turn, that process yields hydrogen fuel that is burned to contribute to meeting approximately 5% of generation needs.

Figure 74. Annual generation mix across all scenarios in 2040 – Current Trends & Policy



The changes from 2032 to 2040 represent the final transition to a carbon-free energy mix. The share of natural gas that remains in the generation mix in 2032 is displaced over this timeframe by additional renewable generation and – in select scenarios – hydrogen combustion.

Figure 75. Annual generation mix across all scenarios in 2040 – Current Trends & Policy



7.3.3 Cost Comparison

In the creation of an MCEP, PNM seeks to develop a plan that limits the costs borne by customers. The primary cost metric considered is the PVRR, which reflects the total cost of generation plus associated transmission over the planning period (2023-2042), discounted back to the start of the analysis horizon. Cost results for all six scenarios analyzed in Phase 3 are shown in Table 57.

Table 57. Present value revenue requirement across scenarios, 2023-2042

Metric	Base Tech	Base Tech + LDES	Base Tech + CT	Base + LDES + CT	All Tech	Base Tech + H_2 Elec
Total PVRR ($M)	**$10,467**	**$10,226**	**$9,611**	**$9,534**	**$9,550**	**$8,985**
Incremental PVRR[A] ($M)	$1,482	$1,241	$626	$549	$565	$0

Table Notes

A. Incremental PVRR measured relative to least cost scenario (Base Tech + H_2 Elec)

These results allow for refinement of the initial findings from Phase 1. Namely:

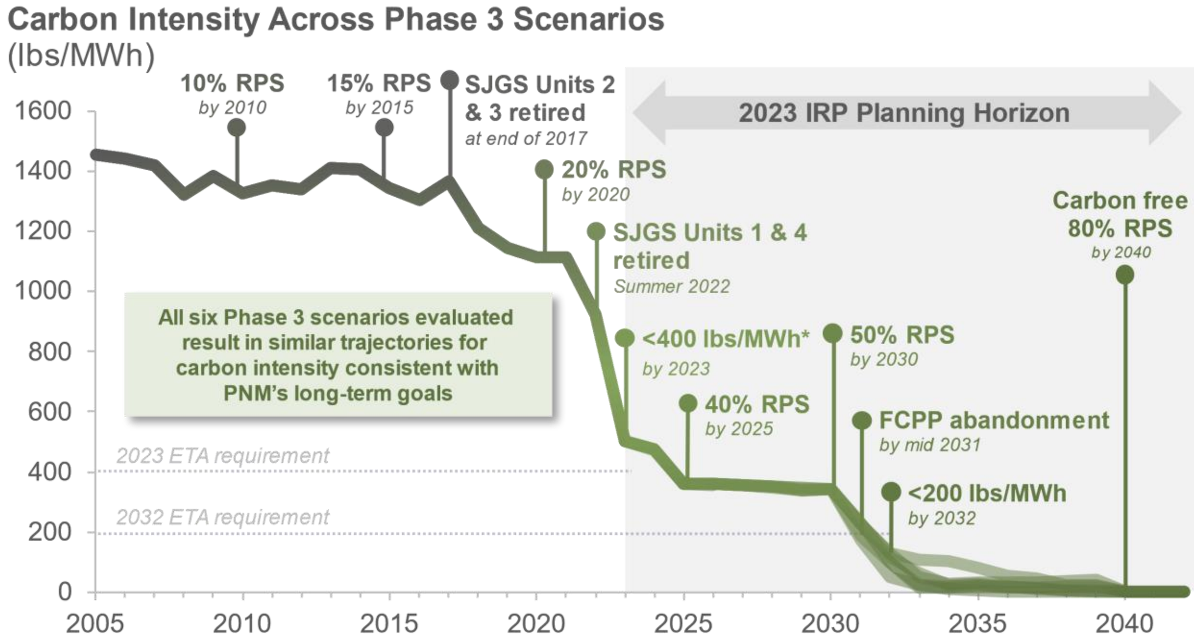
- **A portfolio with only solar, wind, and storage resources is significantly more costly than all alternatives.** In Phase 3, the Base Technologies Only portfolio is refined through further analysis by calibrating it to meet the desired LOLE standard of 0.1 days per year, resulting in the removal of 3,000 MW of battery storage capacity relative to the portfolio results from Phase 1. Even with this final adjustment, the cost of this scenario is an outlier among the six scenarios studied. Because of its relatively high cost, this is not currently a viable strategy to meet long-term goals for affordability, reliability, and carbon reductions.
- **Portfolios that are optimized while allowing for the broadest range of technology options will provide the lowest-cost outcomes for customers.** The portfolio with the greatest number of options resulted in the second lowest cost (second only to the hydrogen electrolysis scenario). This speaks to the importance of a strategy that is technology-agnostic and that is flexible to adapt as emerging technologies mature and are brought to market.
- **The tax credits made available by the IRA make the hydrogen electrolysis scenario the lowest cost.** This scenario has been further refined after Phase 1: while Phase 1 assumed that the capacity of the hydrogen-fueled CT was fixed beyond 2032, this scenario allows for the addition of incremental hydrogen-fueled CTs beyond 2032 (while holding the size of the electrolysis load constant). This enables this scenario to achieve an even lower cost outcome than in Phase 1, as the additional CTs reduce the need to add battery storage resources at relatively low marginal ELCCs.

7.3.4 Environmental Metrics

Greenhouse Gas Emissions

Despite their differences in future resource mix, all scenarios studied in this phase achieve similar greenhouse gas emissions reductions over the planning horizon. The trajectories of greenhouse gas emissions across the six scenarios are shown in Figure 76. Where small differences among cases do exist, these are largely due to differences in the timing of new resource additions but do not reflect any intrinsic difference in the favorability of one scenario over another with respect to the potential for emissions reductions.

Figure 76. Annual carbon intensity across the six Phase 3 scenarios



Reported carbon intensity is calculated from LTCE modeling results by dividing total emissions from PNM internal generation by total annual energy requirements. Actual outcomes may vary depending on final rules adopted by the NMPRC. Delays of replacement resources for SJGS and PVNGS may also have an impact on PNM's ability to meet ETA carbon intensity requirements in 2023 and 2024.

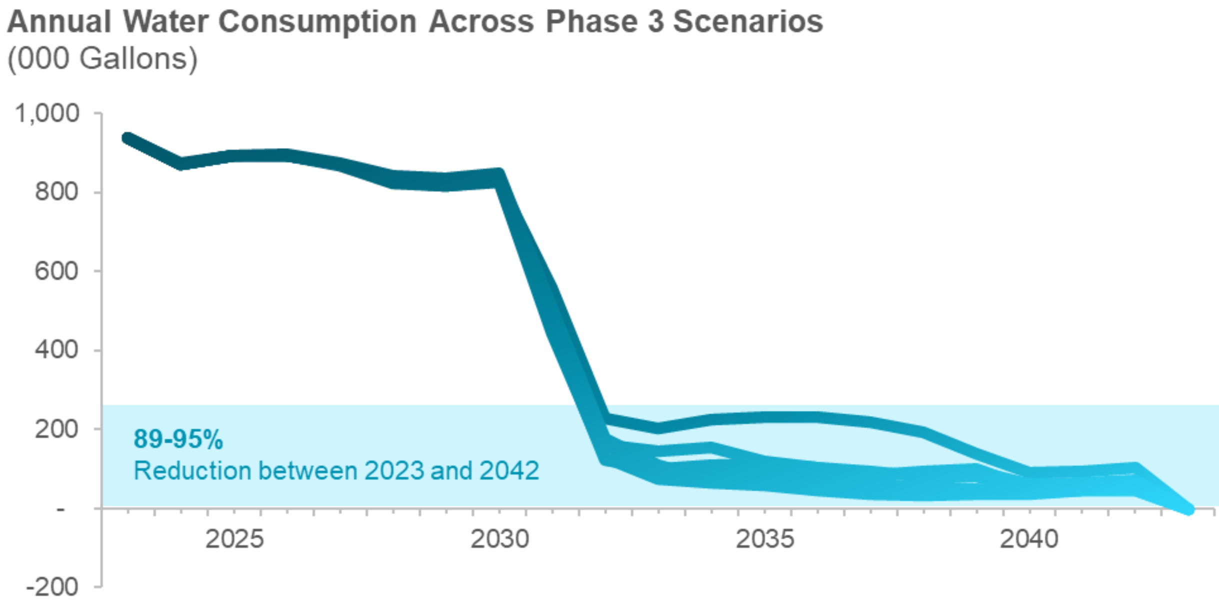
Each portfolio includes sufficient carbon-free generation to achieve key statutory milestones as required by the ETA; specifically:

- In 2024 and all years thereafter, the emissions intensity of all portfolios generally remains below 400 lbs/MWh. The achievement of this milestone is facilitated by the shutdown of SJGS in 2022 and the recent and future planned renewable and storage additions.
- Beginning in 2032, the first full year after PNM's exit from FCPP, all portfolios meet the emissions intensity requirement of 200 lb/MWh. The elimination of coal from the resource mix and the limited reliance on natural gas generators primarily as reliability resources allow all portfolios to achieve very low levels of carbon emissions.

Water Consumption

Figure 77 shows the change in freshwater consumption associated with PNM's portfolio across all Phase 3 scenarios over the planning horizon. Because coal-fired generation accounts for the majority of the system's current freshwater use, all Phase 3 scenarios show a rapid decline in water consumption after PNM's exit from Four Corners. As the transition away from fossil-fueled energy continues, freshwater consumption will also decline.

Figure 77. Annual water consumption across Phase 3 scenarios



7.3.5 Resource Adequacy Analysis

To ensure that the MCEPs each meet standards for reliability, PNM conducted additional analysis on a select set of portfolios using SERVM to simulate the performance of portfolios at two key points in time: 2032 (after PNM's exit from Four Corners, the end of Reeves depreciable life, and expiry of the Valencia PPA) and 2040 (upon reaching 100% carbon-free energy). Due to the similarities between some of the scenarios, only four of the six scenarios were analyzed in this phase: (1) Base Technologies, (2) Base Technologies + LDES, (3) Base Technologies + CT, and (4) All Technologies.

Table 58 summarizes LOLE statistics across the four scenarios modeled in this analysis. In 2032, all four portfolios are slightly more reliable than the 0.1 days per year standard; in 2040, all four portfolios produce an LOLE very close to the 0.1 days per year standard.[49]

[49] This outcome is, in some cases, due to the use of round-trip modeling in SERVM to recalibrate the portfolios developed in EnCompass to align with this standard. See notesTable 58 for Table 58 for information on the portfolio adjustments resulting from the SERVM analysis and Appendices J and N for additional information.

Table 58. Loss of load expectation across select Phase 3 scenarios

Metric	Base Tech	Base Tech + LDES	Base Tech + CT	Base + LDES + CT[C]	All Tech	Base Tech + H_2 Elec[C]
2032 Loss of Load Expectation (LOLE, days/yr)	0.04	0.08	0.05	*n/a*	0.06	*n/a*
2040 Loss of Load Expectation (LOLE, days/yr)	0.10[A]	0.10[B]	0.12	*n/a*	0.09	*n/a*

Table Notes

A. The LTCE portfolio outputs for the Base Tech scenario produced by EnCompass result in an LOLE of 0.02 days per year. To align reliability performance with the other portfolios and the standard, the final portfolio is adjusted by removing 3,000 MW of four-hour battery storage capacity

B. The LTCE portfolio outputs for the Base Tech + LDES scenario produced by Encompass resulted in an LOLE of 0.27 days per year. To align reliability performance with other portfolios and the standard, the final portfolio is adjusted by adding 400 MW of four-hour battery storage capacity

C. Because of similar overall resource mixes to other scenarios, these scenarios were not modeled in SERVM

Timing of Loss of Load Risk

Today, the most prevalent periods of reliability risk (or "loss of load risk") occur in the late summer evenings, as the sun sets and demand for power is still high. As the system evolves, these patterns of loss of load risk will start to shift later in the evening and eventually may migrate to the winter season. Figure 78 shows the incidence of loss of load segmented by month and time of day in the All Technologies scenario in 2040. In this scenario, the predominant periods of loss of load risk are (1) in the summer evenings, stretching all the way to the early morning hours; and (2) in the winter mornings before sunrise. The incidence of extended windows of loss of load risk in both of these periods is a result of the system's high degree of reliance on energy storage; in periods when loads are relatively high and renewable output is relatively low (i.e. outside of daylight hours), system reliability is dependent on the state of charge of energy storage resources. When the amount of energy stored in energy storage devices is exhausted, loss of load is the result.

Figure 78. Share of loss of load hours by month and time of day (All Technologies scenario)

	Hour of Day (MST)																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1		0%	0%	0%	1%	3%	10%	9%																
2					0%	1%	1%	1%																
3																								
4																								
5																								
6					0%	0%														0%	0%			
7	1%	1%	1%	1%	5%	5%	0%												0%	1%	1%	1%	1%	2%
8	1%	0%	0%	0%	1%	2%	1%										0%	1%	1%	0%	0%	0%	0%	1%
9	1%	0%																0%	0%	1%	1%	1%	1%	1%
10																								
11																								
12			0%	0%	1%	6%	16%	12%																

The timing of loss of load risk observed across the other scenarios is similar – in all cases, the summer overnight period and winter early morning period represent the times of year that are most likely to present reliability challenges.

Alternative Reliability Metrics

All portfolios produce LOLE results for 2032 and 2040 that are close to the standard of 0.1 days per year; however, additional reliability metrics help to characterize the nature of reliability risks. While LOLE provides an indication of the frequency of unserved energy events, it provides limited information about their magnitude or duration. For these purposes, Expected Unserved Energy (EUE) and Loss of Load Hours (LOLH) are useful complementary metrics. Interest among reliability planners in understanding these complementary metrics is increasing, as they can provide useful insights into the evolving nature of reliability risks. Table 59 and Table 60 report a more complete set of reliability metrics across the scenarios.

In 2032 (Table 59), all three metrics are similar across the scenarios – that is, portfolios that produce similar results for LOLE also produce similar outcomes for EUE and LOLH. What this generally indicates is that within this timeframe, the changes to the portfolio are likely not significant enough to drive divergent outcomes in frequency, magnitude, or duration of reliability events. In other words, continuing to plan for an LOLE of 0.1 days per year over this period is likely sufficient to produce satisfactory results across a range of reliability metrics.

Table 59. 2032 Loss of load expectation across various scenarios

Metric	Base Tech	Base Tech + LDES	Base Tech + CT	Base + LDES + CT	All Tech	Base Tech + H_2 Elec
Loss of Load Expectation (LOLE, days/yr)	0.04	0.08	0.05	*n/a*	0.06	*n/a*
Expected Unserved Energy (EUE, MWh/yr)	11	10	10	*n/a*	15	*n/a*
Loss of Load Hours (LOLH, hrs/yr)	0.08	0.14	0.10	*n/a*	0.13	*n/a*

In 2040 (Table 60), despite yielding similar outcomes for LOLE, the four portfolios studied produce notable differences in other reliability metrics. For instance, while the Base Technologies and All Technologies scenarios experience an identical frequency of loss of load events (LOLE of 0.09 days per year), the total amount of expected lost load in the Base Tech scenario is larger by a factor of approximately three (EUE of 60 GWh/yr compared to 19 GWh/yr).[50] In general, portfolios with lower quantities of firm resources (Base Technologies and Base Technologies + LDES) yield EUE outcomes that are substantially higher than portfolios with higher quantities of new firm resources. The results for these two scenarios also represent a significant increase in EUE

[50] This divergence in performance across alternative metrics has implications for how PNM plans for long-term reliability. In the longer term, it may make sense to incorporate multi-metric standards for resource adequacy to ensure that performance of the portfolio is satisfactory not only with respect to the frequency of reliability events, but their size and duration as well. However, the results of the analysis to date indicate that this consideration will likely be appropriate in the next decade, and that continuing to utilize the current standard for LOLE is sufficient in the current one.

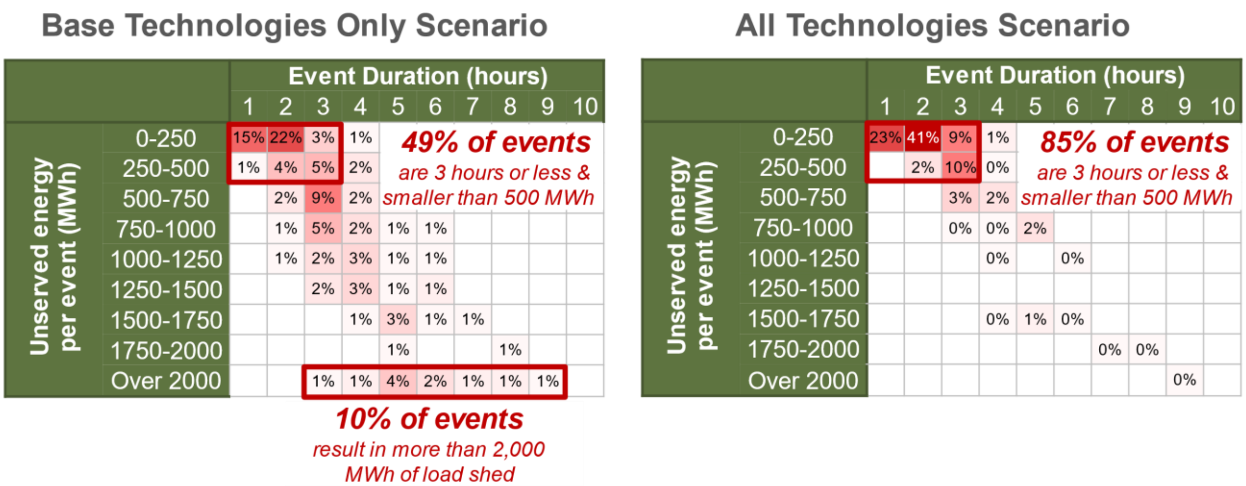
relative to the 2032 portfolios shown above, a further indication that while the frequency of lost load meets the standard, these outcomes would represent a gradual degradation of reliability.

Table 60. 2040 Loss of load expectation across various scenarios

Metric	Base Tech	Base Tech + LDES	Base Tech + CT	Base + LDES + CT	All Tech	Base Tech + H_2 Elec
Loss of Load Expectation (LOLE, days/yr)	0.10	0.10	0.12	*n/a*	0.09	*n/a*
Expected Unserved Energy (EUE, GWh/yr)	60	77	29	*n/a*	19	*n/a*
Loss of Load Hours (LOLH, hrs/yr)	0.28	0.33	0.28	*n/a*	0.21	*n/a*

The difference in performance between portfolios is also apparent in the size and duration of events experienced. Figure 79 compares the frequency of events in the Base Technologies and All Technologies scenarios by their respective durations (in hours) and amount of load that is unserved during a specific event. As shown in Figure 79, loss of load events in the All Technologies scenario (right) tend to be shorter in duration and less severe than in the Base Technologies scenario (left). Specifically, in the All Technologies scenario, 985% of events last three hours or less and require less than 500 MWh of load shed; in the Base Technologies, only 49% of events fall within this range. At the other end of the spectrum, 10% of events in the Base Technologies scenario result in over 2,000 MWh of load shed, while almost no events in the All Technologies scenario exceed this threshold.

Figure 79. Base Technologies vs All Technologies scenarios: frequency of reliability events by duration and unserved energy.



This result – that portfolios with higher quantities of firm resources tend to lead to lower overall unserved energy and reliability events with smaller magnitude and shorter duration – indicates that new firm resources are an important part of the portfolio not only because of the cost savings they produce but also because of their impact on the system's reliability performance.

Furthermore, these findings shed light on the importance of critically evaluating the merits of reliability standards. Both the Base Technologies and All Technologies scenarios meet same frequency of loss load (an LOLE of 0.1 days per year) but yield different durations and magnitudes of loss of load events. Part of PNM's commitment in Action Plan Item 7 is to further investigate the tradeoffs between different reliability targets and their effect on customers.

Role of Gas & Hydrogen Resources

Across all scenarios, natural gas generation resources are critical to PNM's ability to maintain resource adequacy throughout most of the planning horizon. PNM's existing natural gas resources – coupled with additional hydrogen-ready combustion turbines in some scenarios – provide the flexibility to operate at full capacity when necessary for reliability while remaining idle during periods when nuclear, renewables, and energy storage are sufficient to serve PNM's loads. The presence of this type of firm resource is critical to PNM's ongoing ability to ensure reliability without impinging on PNM's ability to make continued progress towards its 2040 carbon-free goals.

The changes in utilization of natural gas and hydrogen resources over time in the All Technologies scenario provides an instructive perspective on the evolution of the role of these types of firm resources in the PNM portfolio. Figure 80 shows the range of potential capacity factors for natural gas and hydrogen resources; the lower end of the range is based directly on the dispatch in EnCompass, while the upper end of the range assumes that market purchases in EnCompass are replaced by generation from PNM's own thermal resources.[51]

Over time – and particularly, as PNM approaches a carbon-free energy portfolio by 2040 – the average capacity factors of natural gas resources decline. This decline in *utilization* of natural gas resources – notwithstanding the increase in overall *capacity* in this scenario – explains how PNM is able to continue the transition towards lower levels of carbon intensity over time while relying on firm natural gas generators for reliability purposes. By 2040, when the remaining natural gas resources transition to hydrogen, the average capacity factor of these thermal resources is expected to be below 10% - meaning that they would only operate during the most constrained conditions as a backstop to maintain system reliability.

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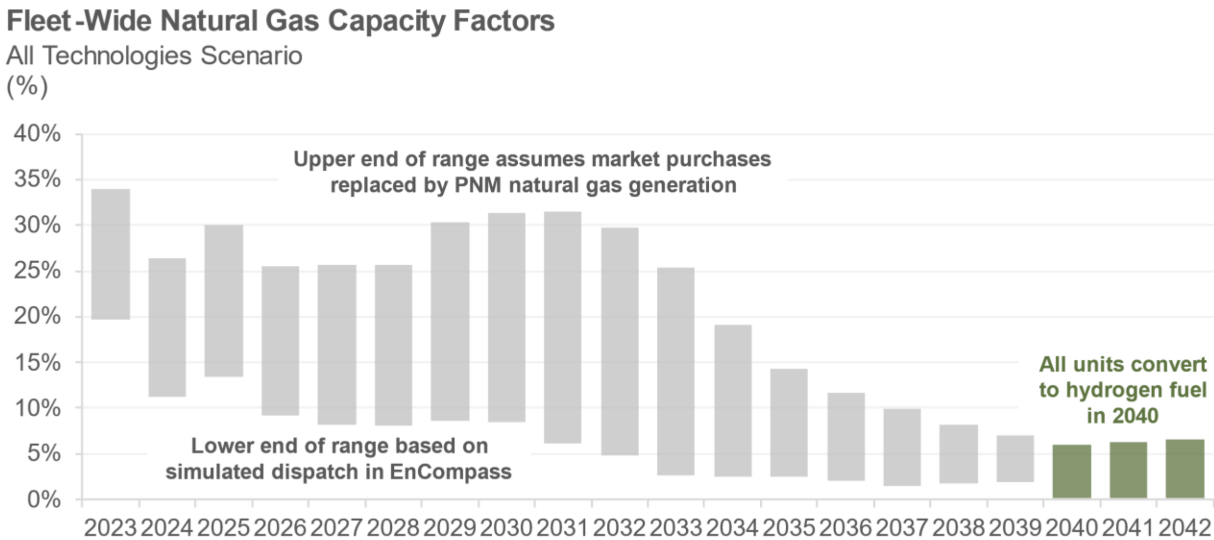
[51] Because the future of wholesale market conditions is highly uncertain and energy may not be available at the prices simulated in EnCompass, this approach provides as an upper bound on the capacity factors should PNM need to operate its own internal resources to meet customer needs.

Figure 80. Average capacity factors of natural gas & hydrogen generation in All Technologies scenario



Sensitivity Analysis on Battery Performance

In response to requests from several stakeholders, this IRP includes some additional sensitivity analyses conducted in SERVM to explore how risk factors associated with specific technologies could impact the reliability outcomes of associated with future portfolios. The sensitivities explored related to two technologies: battery storage and natural gas generation.

Stakeholder Input: Resource Performance Uncertainties

During the facilitated stakeholder meetings, stakeholders presented a number of requests to PNM to conduct additional reliability analysis exploring technology-specific risk factors. Examples of these requests included a desire to explore how uncertainty around how battery performance and degradation would impact reliability, as well as the implications of the risk of correlated outages of natural gas generating infrastructure in the Southwest region. In response to these requests, PNM worked closely with Astrapé to develop several novel sensitivities in SERVM under the All Technologies portfolio to shed light on several of these questions. The results of these analyses are discussed briefly here; more details about findings are provided in Appendix M as well as in meeting contents from prior facilitated stakeholder meetings.

While battery storage has rapidly matured and has now been successfully deployed at grid scale around the country, its long-term performance remains an uncertainty. This IRP studies the impact of altering performance assumptions for battery storage in three sensitivities on the All Technologies scenario:

- A reduction in round-trip efficiency from 85% to 75%;
- A reduction in energy storage capacity (MWh) of 10% relative to rated duration, and;
- A reduction in energy storage capacity (MWh) of 25% relative to rated duration (effectively reducing a four-hour battery to a three-hour battery).

All three may be understood as proxies for the possible impacts of degradation over time.

The impacts of these sensitivities on the realized LOLE of the All Technologies portfolio in 2040 are shown in Table 61. The impacts of the first two sensitivities are relatively modest: under base case assumptions, the LOLE in the All Technologies scenario is 0.09 days per year; the 75% RTE and 10% energy capacity degradation sensitivities result in increases to 0.12 and 0.1 days per year, respectively. Considering that this portfolio includes nearly 2,000 MW of battery storage – a large amount of capacity when compared with peak demand – these results indicate a relatively robust portfolio if deviations from rated performance assumptions are modest.

However, at higher levels of degradation (25% energy capacity degradation), the impacts become more pronounced, and the LOLE increases to 0.21 days per year. Ultimately, this outcome could be mitigated with additional resource investments, rather than accepting a lower level of reliability – though those additional resources would result in increased costs.

Table 61. Impacts of battery storage sensitivities on reliability metrics, All Technologies scenario

Metric	All Tech	All Tech (75% Storage RTE)	All Tech (15% Energy Storage Degradation)	All Tech (25% Energy Storage Degradation)
Loss of Load Expectation (LOLE, days/yr)	0.09	0.12	0.10	0.21
Expected Unserved Energy (EUE, MWh/yr)	16	26	23	60
Loss of Load Hours (LOLH, hrs/yr)	0.20	0.26	0.24	0.48

Sensitivity Analysis on Natural Gas Correlated Outages

The second category of sensitivities on resource performance explored in the IRP relates to the risk of correlated outages among natural gas generators. In response to these requests, PNM worked directly with Astrape to explore several novel sensitivities in SERVM under the All Technologies portfolio to shed light on several of these questions. The results of these analyses are discussed briefly here; more details about findings are provided in Appendix M as well as in meeting contents from prior facilitated stakeholder meetings.

This sensitivity compares two different outage scenarios against the base case simulation:

(1) One in which the risk of correlated outages is limited to PNM's thermal resources; and
(2) One in which the entire desert southwest region experiences correlated outages.

In the base case SERVM analysis, the outage patterns modeled for natural gas generators are consistent with PNM historical experience, so modeling the effects of correlated outages requires the use of an alternative hypothetical relationship between cold temperatures and plant outage probabilities. For the purposes of this sensitivity, correlated outages are modeled as a function of temperature using a relationship consistent with outage rates observed in Texas during Winter Storm Uri. In many respects, this reflects a "worst-case" outcome for correlated outages and may not be reflective of actual plausible conditions in the PNM system.

Stakeholder Input: Correlated Outage Risks

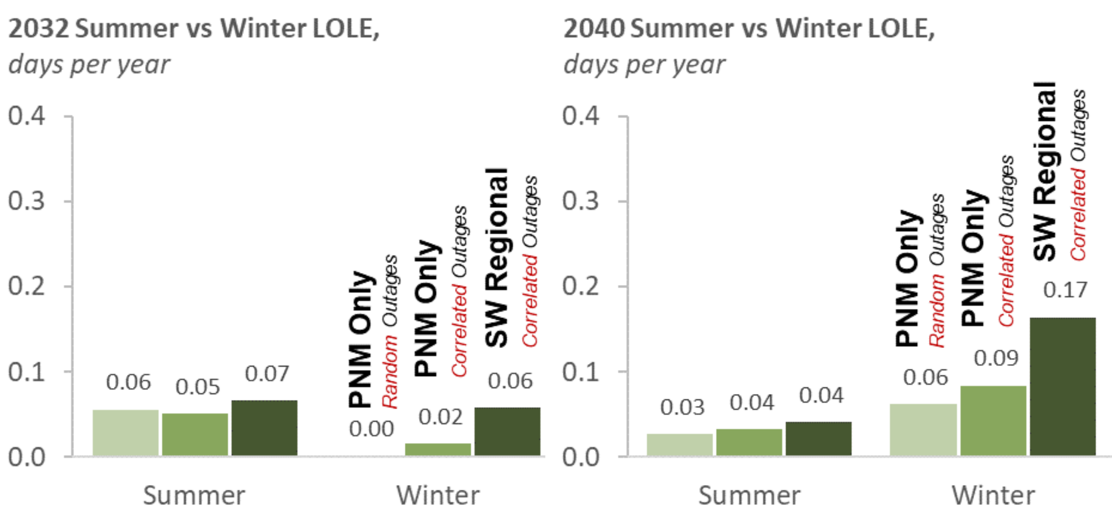
One of the questions raised by stakeholders during the facilitated stakeholder process was whether the risk of "correlated outages" of natural gas generation would pose a significant risk to reliability. There are multiple examples over the past fifteen years of severe winter storms triggering widespread outages of natural gas production, transportation, and generation infrastructure – in some cases, with catastrophic results. Examples include:

- In Winter 2011, a cold snap over the Southwest region triggered a natural gas production freeze off. This coincided with higher-than-usual outages at coal and gas generators due to extreme weather conditions, ultimately resulting in some load shedding in the Southwest region.
- In 2021, Winter Storm Uri caused widespread failures of gas pipelines and generators in the state of Texas, which experienced severe blackouts that spanned a three-day period.
- Most recently, in 2022, the severe conditions of Winter Storm Elliott led to significant quantities of natural gas generator outages across the southeastern US, resulting in many utilities shedding load.

Such correlated outages that lead to widespread regional failures of generating infrastructure and ultimately threaten reliability are rare events; however, their occurrences have proven catastrophic for public health and safety. For this reason, it is useful to understand how PNM's system would perform under such catastrophic conditions. However, it is also true that the risk of correlated outages is highly idiosyncratic and difficult to generalize from one system to another, so the types of conditions that manifest in one part of the country may not be realistic in another. In PNM's system, historical data over the past ten years indicates limited risks of these types of correlated outages – particularly when compared against the risks observed in other regions of the country. PNM will continue to monitor this risk, but it is also essential to ground resource adequacy planning in high-quality data that is specific to PNM's system.

Figure 81 shows the increased risk of loss of load in the All Technologies scenario resulting from the modeling of correlated outages for 2032 and 2040.

Figure 81: All Technologies Scenario: Correlated Outage Reliability Sensitivities



These results show two main takeaways:

1. **The risk of correlated outages leading to reliability risk in the winter is more pronounced in the long-term, rather than the near-term.** By 2032, the thermal fleet plays a relatively small role in PNM's total portfolio. Even with regional outages in the summertime, high renewable output, especially from solar, and storage resources mitigate against correlated outages. By 2040, the net load risks spreads to both summer and winter, therefore, the impacts of correlated outages become more material relative to 2032.
2. **Depending on the geographic footprint of the cold snap, winter loss of load risk increases as other entities experience thermal outages.** When solar and wind output are limited during the colder months, thermal outages increase risk of loss load. Loss of load risk increases further should cold weather cause widespread outages throughout the region.

Sensitivity Analysis on Market Support

While both portfolios meet PNM's standard for resource adequacy, all scenarios rely on purchases from wholesale markets to meet this standard, some more than others. The Base Technologies and Base Technologies + LDES scenario has a lower quantity of firm resources and a larger quantity of energy storage resources. Whereas the firm resources in the Base Technologies + CT portfolio can operate at full capacity on a sustained, around-the-clock basis when needed for reliability, storage resources portfolio are limited by duration. In the cases with limited firm generation, when their state of charge is exhausted, the assumed market purchases provide the energy needed to ensure reliability. As a result, PNM's ability to maintain resource adequacy in a world with limited firm generation is more sensitive to the availability of imports from other entities in the region.

The difference between portfolios is noteworthy because of the inherent uncertainty that exists in projections of the conditions that will exist in the Western wholesale market beyond the next few years. As the mix of resources continues to shift towards greater levels of renewables and storage across the region, it is difficult to quantify exactly when and how much surplus will be available for purchase. Due to these results, one core action outlined in the Action Plan Item is to explore benefits of joining regional markets and regional planning program, like Western Resource Adequacy Program.

7.3.6 Resilience Analysis

As the frequency of extreme weather increases, planning must consider the impacts of unlikely but highly consequential events (sometimes known as "High Impact, Low Frequency" events, or HILF events). For the IRP, future portfolios are simulated under the extreme weather conditions experienced in two such historical events: (1) a severe winter storm based on conditions experienced from January 23-29, 2011, and (2) a summer heat wave based on conditions experienced from August 16-22, 2020.

These two historical periods are used in this IRP as resilience stress tests, whereby the specific historical conditions observed during those two weeks are imposed upon a future portfolio's loads and resources to evaluate the reliability risks associated with such extreme events.

The resilience analysis relies on SERVM, the same loss-of-load-probability model used for the resource adequacy study, to assess the performance of Phase 3 portfolios in an extreme winter and an extreme summer event. Like the reliability analysis, this analysis explores and measures the performance of portfolios across risk periods, but for this study, the focus is on the rare and catastrophic events.

Each extreme weather event is analyzed under two "external market conditions": (1) "full market support," which reflects the same modeling assumptions used in the resource adequacy simulations, and (2) "no market support," which treats PNM as an electrical island for the purposes of the resilience analysis. While the latter condition may appear extreme, it is a useful bookend that can characterize the extent to which PNM's portfolio of resources could self-sufficiently meet customer needs during extreme weather and the amount of PNM's retail load that would be at potential risk of load shedding depending on prevailing conditions in regional wholesale markets.

Table 62 summarizes the outcomes of this analysis under the "full market support" condition. These results support three notable observations:

1. All scenarios experience some amount of unserved energy, an important reminder that no portfolio is perfectly reliable, and that all portfolios can experience extreme events that require load shedding.
2. Winter loss of load events in 2040 tend to be larger in magnitude than summer events. This stems from the fact that one of the primary drivers of reliability challenges in a low-carbon electricity portfolio is sustained periods of low renewable production that coincide with high loads – which tend to occur in the winter.
3. Scenarios with limited firm generation are more susceptible to larger loss of load events than those with more firm generation, particularly in the winter. Specifically, the Base Technologies + CT and All Technologies cases both exhibit lower amounts of unserved energy than other scenarios studied.

Table 62. Unserved energy results for summer & winter resilience tests in 2040, Full Market Support

	Unserved Energy Observed Across the Week (MWh)					
Period	**Base Tech**	**Base Tech + LDES**	**Base Tech + CT**	**Base + LDES + CT**	**All Tech**	**Base Tech + H_2 Elec**
Extreme Summer Week	454	1,732	74	*n/a*	103	*n/a*
Extreme Winter Week	2,717	1,380	980	*n/a*	610	*n/a*

The loss of load outcomes for the scenarios studied without regional market support are summarized in Table 64. The most significant impact resulting from the elimination of market support is the significant increase in winter vulnerability: the amount of unserved energy observed across the extreme winter week increases by factors of five to ten. This result is noteworthy for two reasons: (1) it implies that the presence of the regional market will be crucial to mitigating the potential reliability impacts of extreme weather events upon PNM's customers, and (2) it indicates that the nature of that exposure to market conditions is significantly greater in scenarios without new firm generation resources, in which the amount of load at risk during the extreme week is larger by a factor of two to three times.

Table 63: Unserved energy results for summer & winter resilience tests in 2040, No Market Support

Unserved Energy Observed Across the Week (MWh)

Period	Base Tech	Base Tech + LDES	Base Tech + CT	Base + LDES + CT	All Tech	Base Tech + H_2 Elec
Extreme Summer Week	274	2,156	19	*n/a*	17	*n/a*
Extreme Winter Week	13,070	18,542	5,390	*n/a*	4,862	*n/a*

To provide a more concrete picture of the contrasting reliability challenges encountered in these scenarios, Figure 82 shows the dispatch of the PNM system during the extreme winter week under the no market support condition. The principal difference between these two cases is the realization of load shedding: in the Base Technologies scenario, extreme weather leads to three consecutive days of large load shedding events (where in some periods, more than half of PNM's load is interrupted). In contrast, while the All Technologies scenario also experiences three consecutive days of load shedding events, two of those events are comparatively very small, and the size of the largest event is mitigated relative to the Base Technologies scenario. While any load shedding event would have adverse consequences upon PNM's customers, the impacts of major energy shortfalls such as those observed across all three days in the Base Technologies scenario or the second day of the All Technologies scenario would be substantially more disruptive. These figures are accompanied by the subsequent Table 64, which provides a more detailed narration of the events leading to the load shedding events in each case.

These examples highlight the importance of firm resources in contributing to reliability needs and mitigating risks of lost load due to their ability to operate at full capacity over sustained periods of time (in this case, 16-hour long overnight windows) for multiple days without the need to recharge from the grid. Because of its intrinsic limits on duration (in this analysis, four hours), battery storage is an ineffective substitute: it would take 4 MW of storage to produce 1 MW of sustained power output over a 16-hour period. This also speaks to why long-duration storage resources may serve as effective substitutes to traditional sources of firm capacity like natural gas.

Figure 82. 2040 dispatch during extreme winter week, Base Technologies Only and All Technologies scenarios (No Market Support scenario)

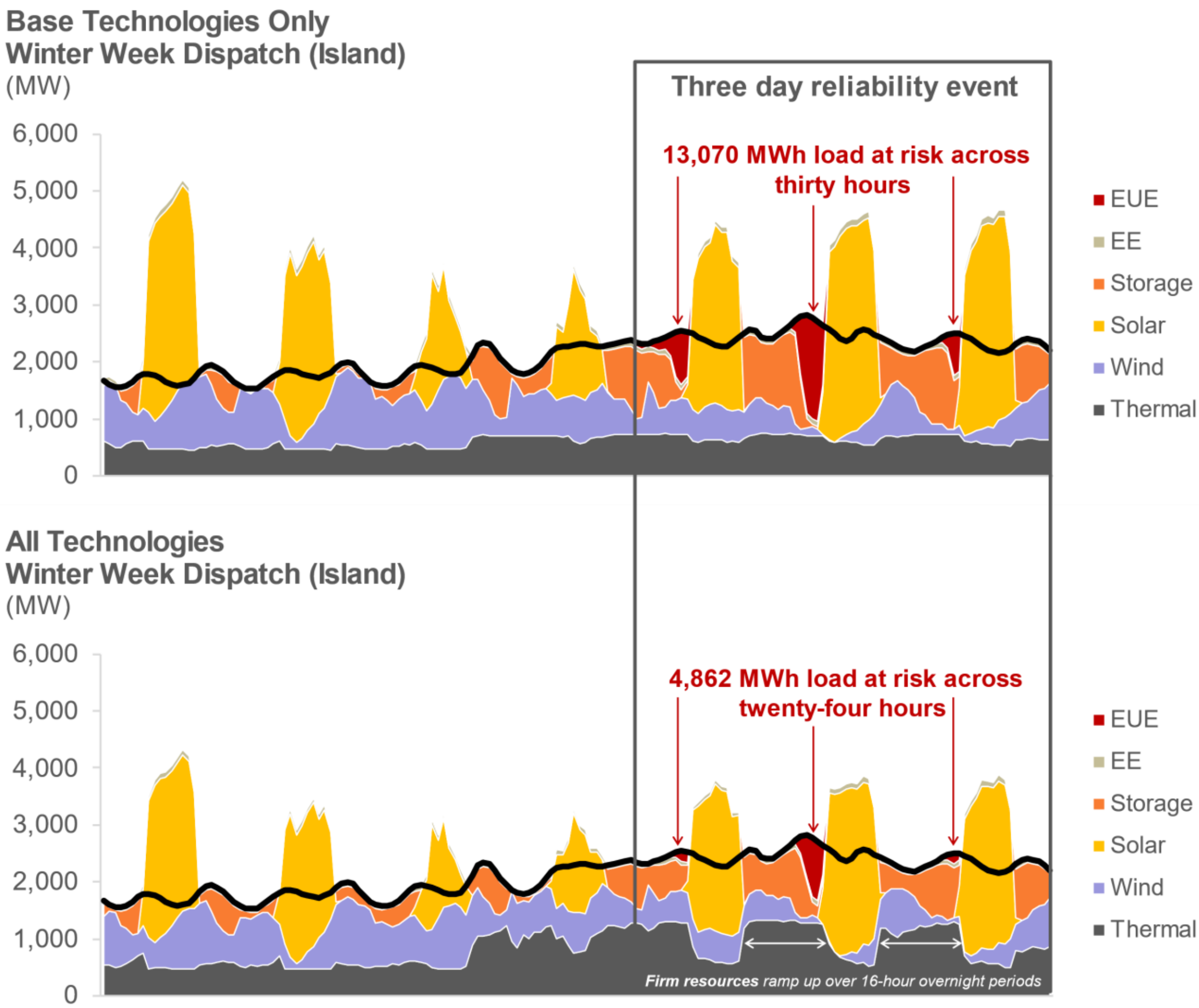


Table 64. Detailed accounts of conditions that lead to load shedding in resilience simulations

Period	General Conditions	Base Technologies Dispatch	All Technologies Dispatch
Days 1 & 2	Typical load and solar shapes for February; sustained high wind output	Nuclear and renewable generation is sufficient to meet load in most hours; storage dispatches during limited nighttime hours and recharges during the day	Nuclear and renewable generation is sufficient to meet load in most hours; storage dispatches during limited nighttime hours and recharges during the day
Days 3 & 4	On both days, renewable output is limited. Storage charging opportunities are limited, thus only able to partially charge	Storage charging opportunities are limited, thus only able to partially charge. Discharge is still needed during periods of low renewable output	Storage charging opportunities are limited, thus only able to partially charge. Discharge is still needed during periods of low renewable output
Day 5	Loads increase as temperatures begin to drop. Solar output returns to typical seasonal level.	By early morning, storage state of charge is exhausted. With no other dispatchable generators available, a large amount of load shedding occurs in the morning before sunrise. **Loss of load: 197 MWh, 4 hours** **Loss of load (no market): 3,673 MWh, 14 hours**	Sustained output from firm resources in the morning mitigates the need to rely on storage. Once storage runs out of charge, continued operations of firm resources limits the amount of load shed. **Loss of load: 33 MWh, 3 hours** **Loss of load (no market): 610 MWh, 6 hours**
Day 6	Extreme cold weather and high pressure system leads to high morning loads and low wind production; typical seasonal solar production	Operating dynamics from previous day are exacerbated by higher loads. Having recharged the previous day, storage is again exhausted during early morning, and large load shedding event occurs for the second day in a row. The size of this event is exacerbated by low wind output coincident with the coldest temperatures. **Loss of load: 2,409 MWh, 5 hours** **Loss of load (no market): 7,617 MWh, 9 hours**	Operating dynamics from previous day are exacerbated by higher loads. Even presence of dispatchable firm generators cannot avoid need to shed significant amounts of load before sunrise. The size of this event is exacerbated by low wind output coincident with the coldest temperatures. **Loss of load: 943 MWh, 5 hours** **Loss of load (no market): 3,812 MWh, 8 hours**
Day 7	Conditions become more mild, as warmer temperatures result in lower overall loads relative to previous day. Low wind output in the morning makes for challenging conditions.	Similar dynamics from previous day repeat; however, milder conditions result in lower quantities of loss of load **Loss of load: 111 MWh of load shed over three hours** **Loss of load (no market): 1,781 MWh, 7 hours**	Conditions are nearly mild enough to avoid loss of load altogether, as combination of firm resources and storage meets almost all loads **Loss of load: 3 MWh load shed over three hours** **Loss of load (no market): 440 MWh, 6 hours**
Total		Three days with significant loss of load events **Loss of load: 2,717 MWh over twelve hours** **Loss of load (no market): 13,070 MWh, 30 hours**	One day with a significant loss of load event; two days with smaller load shedding events **Loss of load: 979 MWh over eleven hours** **Loss of load (no market): 4,862 MWh, 24 hours**

7.3.7 Alternative Futures & Sensitivities

In addition to the portfolios presented (Section 7.3.1), sensitivity analysis is performed using each scenario for the Current Trends and Policy future and explored portfolio changes under different Futures. For more details on sensitivities and futures, see Section 5.1.3.

In the Phase 3 analysis presented above, the resource adequacy analysis resulted in a significant adjustment to the Base Technologies portfolio (resulting in the removal of 3,000 MW of four-hour storage from the portfolio output by the capacity expansion model to calibrate to 0.1 days per year). This level of detailed analysis was not possible to undertake for all futures and sensitivities. Instead, that same adjustment is applied to all futures and sensitivities for the Base Technologies portfolio. While this is an imperfect solution, it provides more instructive relative comparisons among the various scenarios tested. The nature of this adjustment, including both results prior to and after the adjustment is made, are reported in Appendix J.

7.3.7.1 Alternative Futures

As described in Section 5.1.2, the IRP includes four futures in this IRP: Current Trends and Policy (CTP), National Climate Policy (NCP), High Economic Growth (HEG), and Low Economic Growth (LEG). Comparative analysis of each portfolio across the different futures is useful for two reasons: (1) it allows PNM to understand the extent to which alternative futures would indicate a different portfolio of investments would achieve lowest costs, and (2) it shows the relative cost impacts of various factors outside of PNM’s control.

Table 65 presents the PVRR results across all scenarios and futures modeled in Phase 3. Not surprisingly, the total PVRR results are highly sensitive to the underlying assumptions regarding load growth: when modeled under the Low Economic Growth scenario, all PVRRs decrease relative to the Current Trends & Policy future, whereas in the High Economic Growth and National Climate Policy futures – both of which assume significant amounts of load growth – the PVRRs are significantly higher due to incremental resource needs.

Table 65. Total PVRR (2023-2042) across all Phase 3 scenarios & futures, $ millions

Future	Base Tech	Base Tech + LDES	Base Tech + CT	Base + LDES + CT	All Tech	Base Tech + H_2 Elec
CTP	$10,467	$10,226	$9,611	$9,534	$9,550	$8,985
HEG	$17,448	$15,173	$13,497	$13,515	$12,844	$13,482
LEG	$9,495	$9,614	$9,122	$9,084	$9,065	$8,615
NCP	$19,531	$16,015	$13,710	$12,959	$12,734	$14,897

Comparisons among the different scenarios within a single future also provide useful insights. Table 66 shows the incremental PVRR relative to the lowest cost scenario for each future. Across the four futures, there are two scenarios that appear as least cost: Base Technologies + Electrolysis (in the CTP and LEG futures) and All Technologies (in the HEG and NCP futures). Three observations are notable with respect to this result:

- The All Technologies scenario’s lowest cost result under the two cases with very high load growth speaks to the power and versatility of an “all-of-the-above” strategy that considers the widest set of technologies compatible with PNM’s goals. This scenario outperforms all others by moderate to significant margins because it is able to take advantage of so many complementary solutions (see subsequent discussion on composition of portfolios).

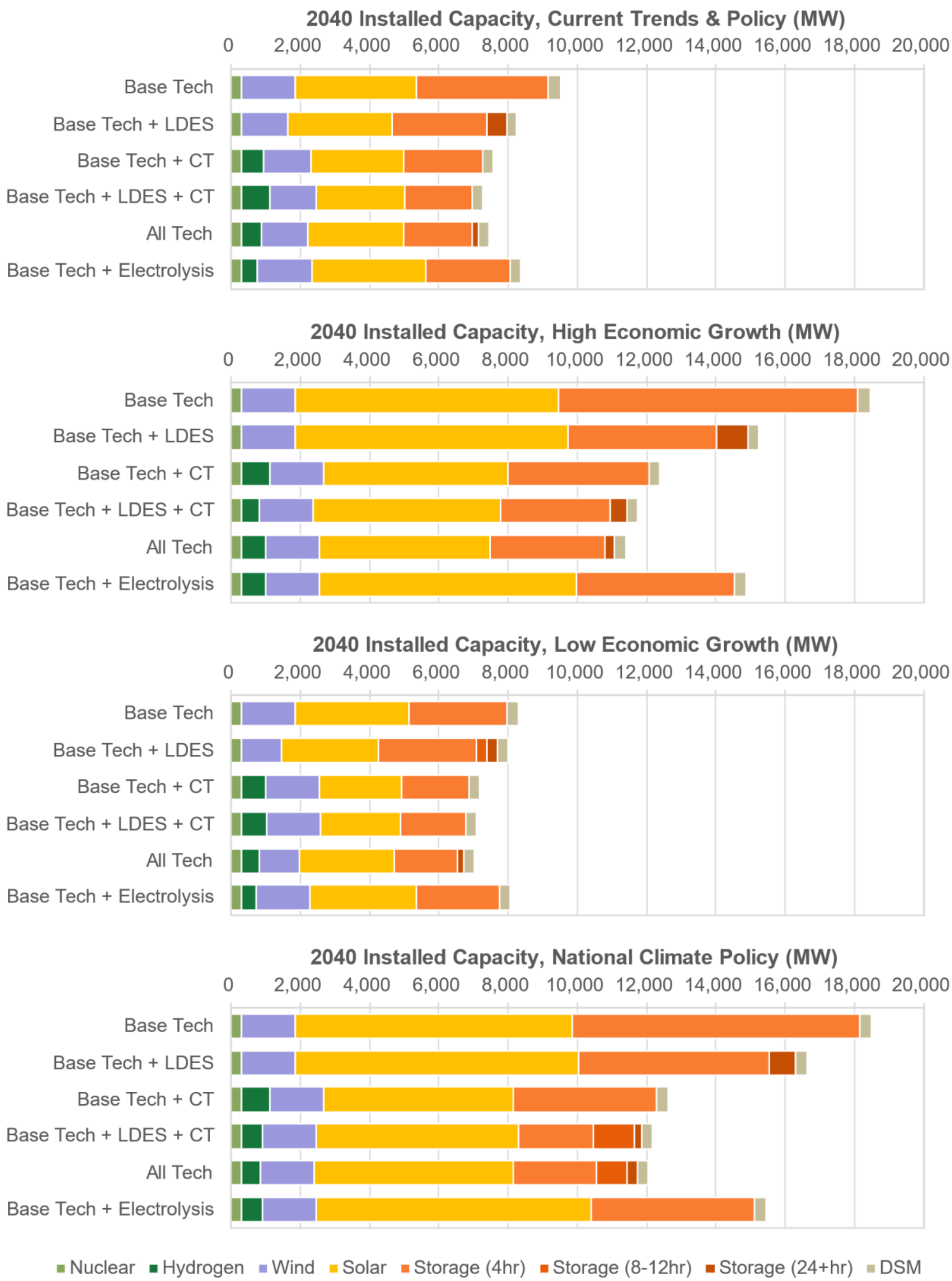
- Even under a National Climate Policy future that requires PNM achieve a 100% clean energy portfolio by 2035, investments in new hydrogen-ready thermal resources are included among a diverse portfolio of options in the least-cost portfolio (All Technologies). This outcome indicates that this strategy is robust even considering the possibility of increasingly stringent federal policy around emissions.
- At first glance, the high incremental cost of the Base Technologies + Electrolysis scenario under the NCP future may seem like an indictment of hydrogen as incompatible with extremely aggressive climate policy. This would be a misinterpretation of these results, which stem from the fact that the assumptions for this scenario, wherein the capacity sizing of the electrolysis load is fixed at a static level as an input, would not have made for scalable results to higher levels of load growth. The lack of *other* firm resource options in this case would therefore have contributed to this result, but a scenario defined with more flexibility in hydrogen infrastructure sizing could likely have yielded more favorable cost outcomes.

Table 66. Incremental PVRR (2023-2042) relative to the lowest cost scenario for each future, $ millions

Future	Base Tech	Base Tech + LDES	Base Tech + CT	Base + LDES + CT	All Tech	Base Tech + H_2 Elec
CTP	+$1,482	+$1,241	+$626	+$549	+$565	-
HEG	+$4,604	+$2,329	+$654	+$671	-	+$639
LEG	+$880	+$999	+$507	+$469	+$450	-
NCP	+$6,797	+$3,281	+$976	+$225	-	+$2,163

Figure 83 shows the total installed capacity in 2040 for all scenarios. The differing levels of load growth associated with the futures drive dramatic differences in the quantity of resources needed to satisfy reliability and clean energy objectives: in most scenarios, the portfolio in the High Economic Growth future includes nearly double the quantity of resources in the Low Economic Growth scenario. But while the level of resource development changes with each future, the relative resource mixes in each of the different scenarios does not differ significantly. All scenarios rely very heavily on wind, solar, and storage resources; in scenarios that allow for new hydrogen-ready CTs, they are selected in small quantities to ensure reliability (even in the National Carbon Policy future); and small amounts of long-duration storage resources are typically selected in scenarios where they are available.

Figure 83. Total 2040 installed capacity across all scenarios and futures



7.3.7.2 Sensitivity Results

As mentioned in Section 5.1.3, different load forecasts are applied to the Current Trends and Policy future. These sensitivities measure the risks and impact of individual forecast elements upon the portfolio and the consequential costs, environmental impacts, and reliability outcomes. Table 67, Table 68, and Figure 84 present each sensitivity's net present value of revenue requirements, present value of total emissions, and range of portfolio builds for specific technologies produced across all sensitivities.

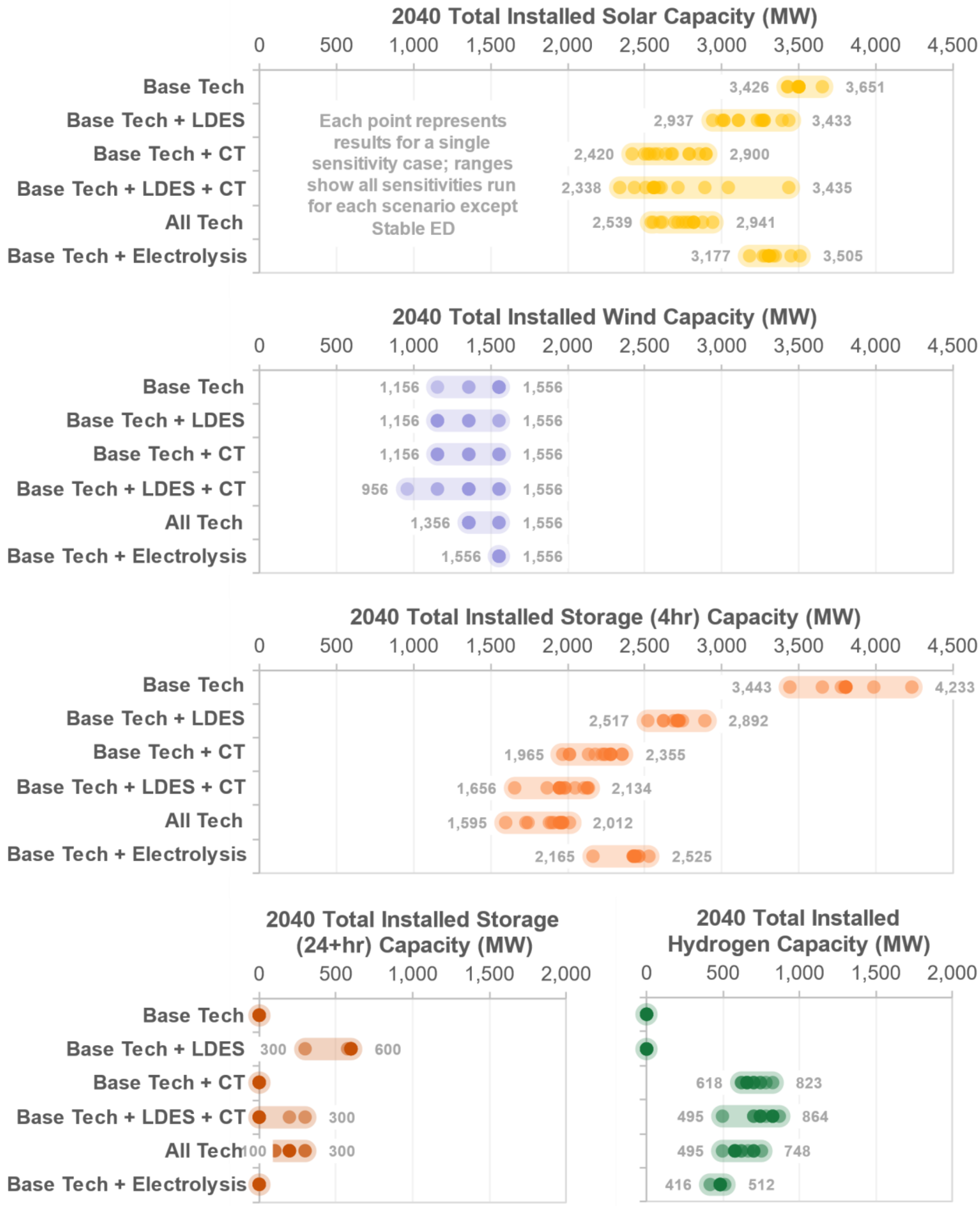
Table 67. Present Value Revenue Requirement for all sensitivities in $MM

Sensitivity	Base Tech	Base Tech + LDES	Base Tech + CT	Base Tech + LDES + CT	All Tech	Base Tech + H_2 Elec
Current Trends & Policy	**$10,467**	**$10,226**	**$9,611**	**$9,534**	**$9,550**	**$8,985**
DERMS	$10,187	$9,997	$9,300	$9,258	$9,291	$8,706
FCPP 2027 exit	$10,477	$10,293	$9,547	$9,496	$9,507	$8,926
High EV	$10,823	$10,508	$9,827	$9,750	$9,821	$9,155
High Gas Prices	$10,532	$10,329	$9,712	$9,658	$9,669	$9,048
High Tech Costs	$11,379	$10,520	$9,949	$9,919	$9,798	$9,442
Low Gas Prices	$10,306	$10,117	$9,442	$9,398	$9,420	$8,851
Low Tech Costs	$9,976	$9,431	$9,343	$9,272	$9,215	$8,657
NMPRC CO2 0	$10,368	$10,155	$9,521	$9,463	$9,505	$8,914
NMPRC CO2 20	$10,705	$10,527	$9,862	$9,800	$9,835	$9,241
NMPRC CO2 40	$10,988	$10,820	$10,157	$10,103	$10,156	$9,536
NMPRC CO2 8	$10,507	$10,299	$9,655	$9,596	$9,582	$9,065
Stable ED	$16,026	$14,385	$12,772	$12,824	$12,509	$12,499
Tax credit 10-yr exp.	$11,555	$10,608	$9,740	$9,854	$9,654	$9,311
TOU	$10,078	$10,173	$9,512	$9,452	$9,511	$8,897

Table 68. Present Value Carbon Emissions for all sensitivities in Million Tons of CO2

Sensitivity	Base Tech	Base Tech + LDES	Base Tech + CT	Base Tech + LDES + CT	All Tech	Base Tech + H_2 Elec
Current Trends & Policy	**15.1**	**15.4**	**16.4**	**15.9**	**15.1**	**15.6**
DERMS	15.3	15.5	16.1	16.1	15.3	15.5
FCPP 2027 exit	12.7	13.0	14.0	14.1	13.1	13.5
High EV	15.4	15.3	16.6	15.8	15.2	15.6
High Gas Prices	15.3	15.2	15.6	15.7	14.6	15.5
High Tech Costs	15.7	15.6	16.5	16.2	15.5	15.9
Low Gas Prices	15.4	15.5	16.5	16.5	15.6	15.7
Low Tech Costs	15.3	15.5	15.8	15.3	15.2	15.6
NMPRC CO2 0	15.5	15.7	16.3	16.1	15.2	15.7
NMPRC CO2 20	15.2	15.2	15.6	15.9	14.9	15.5
NMPRC CO2 40	15.1	15.0	15.6	15.6	14.7	15.3
NMPRC CO2 8	15.4	15.4	15.8	15.9	15.2	15.6
Stable ED	16.6	16.7	19.1	18.2	16.9	18.6
Tax credit 10-yr exp.	15.2	15.6	15.7	15.4	15.2	15.5
TOU	15.5	15.5	16.3	16.0	15.3	15.7

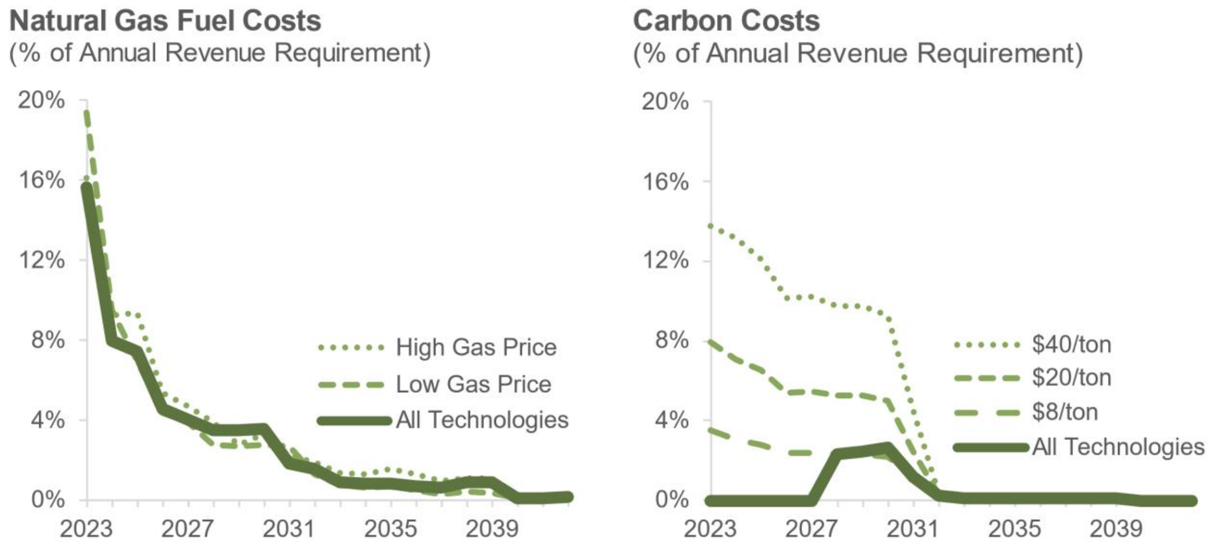
Figure 84. Total installed capacity ranges in 2040 across sensitivities



These results strengthen PNM's confidence in the findings described above and provide some additional insights that build upon them (Sections 7.2.2 and 7.3.3). Namely:

- **Across nearly all sensitivities, the scenarios with the broadest set of available resource options produce the most favorable cost outcomes.** Across the first five scenarios modeled (i.e. excluding the Base Technologies + Hydrogen Electrolysis scenario), the All Technologies and the Base Technologies + LDES + CT scenarios are the two cases that yield the lowest cost results across all sensitivities. In most cases, their PVRRs are within tens of millions of one another. Both scenarios include both long duration storage and hydrogen-ready CTs in addition to the "base" technologies (solar, wind, storage, and DSM).
- **Consistent with PNM's previous applications to the Commission, an early exit from FCPP provides environmental benefits and generally appears to have cost savings for customers.** PNM has previously filed an application with the Commission to exit its share of FCPP prior to the end of the 2031 operating agreement on the basis of cost savings and environmental benefits for customers, and some scenario analysis in this IRP appears to reaffirm those results. Across all sensitivities, the cases with a 2027 exit from FCPP (rather than 2031) produce the most significant incremental emissions reductions relative to the Base Case. On a net present value basis, emissions from 2023-2042 range from 15 to 16 million tons of carbon; in the FCPP 2027 exit sensitivity, emissions range from 13 to 14 million tons, representing a reduction in emissions of roughly 20% across the-20-year planning horizon. At the same time, most of the FCPP 2027 Exit sensitivities also show some cost savings on a net present value basis, with two exceptions – the Base Technologies and the Base Technologies + LDES scenarios. Each exhibits higher costs under a FCPP 2027 Exit sensitivity. What these scenarios share in common is the lack of a new firm resource available in the 2027 timeframe (due to lack of maturity and long lead times, the LDES options are not available until after 2028), indicating the importance of consideration of firm resources as part of any early exit strategy for FCPP. Supply chain risks would warrant consideration given the clear need for firm resources in the timeframe.
- **The costs of fuel and carbon will represent a declining portion of PNM's revenue requirement over time.** Largely due to PNM's plans to transition towards a portfolio that eliminates reliance on carbon-emitting fossil fuels, the costs associated with those components of the portfolio will progressively decrease. Beyond 2030, as the carbon intensity and fuel consumption of the portfolio continues to decline, these prices have a similar small impact on overall portfolio cost (even as uncertainty in future *prices* for natural gas and carbon persists). See Figure 85 for an illustration of this trend in the All Technologies scenario and associated sensitivities.

Figure 85. Natural gas and carbon costs as a share of total revenue requirement under a range of sensitivities



- **As PNM's portfolio transitions from "fuel to steel," technology cost uncertainty presents a greater cost risk to customers than fuel price uncertainty.** The difference in PVRR between the Low and High Technology Cost sensitivities ranges between $583 million to $1,403 million, whereas the difference in PVRR between the Low and High Gas/CO2 Price sensitivities ranges between $197 to $270 million. This is predominantly the result of the increasing reliance on resources that do not require fuel to generate electricity in the transition towards a carbon-free electricity system; the corresponding reduction in exposure to fuel prices is a benefit of that transition. This observation has important implications for how PNM manages risk and maximizes value for customers; namely, it will be crucial to take full advantage of IRA tax credits and seek out low-cost opportunities to develop carbon-free resources to support the transition.
- **Scenarios with increased electrification require accelerated investment to ensure resource adequacy and meet clean energy goals.** In sensitivities with accelerated electric vehicle adoption and stable economic growth, the rate of resource development must grow to meet the increased electricity demand. To support deployment of EVs, the portfolio increases its low-cost carbon-free and dynamic balancing resources to meet incremental demand.
- **Direct engagement with customers through innovative programs can provide benefits that facilitate the transition.** This IRP includes two sensitivities that explore the impacts of collaboration between PNM and its customers – a TOU rate sensitivity and a DERMS sensitivity. Both sensitivities indicate potential savings for customers – between $229 and $311 million in the DERMS sensitivity and $39 and $389 million in the TOU sensitivity – due to avoided investments in new generating infrastructure based on customers' behavioral change in response to incentives. PNM views its customers as partners in the effort to transition to an affordable, clean electricity system and will endeavor to develop such programs when and where concrete benefits can be identified.

7.3.8 Qualitative Discussion of Risks

With few exceptions, many of the risks identified and discussed below are relevant to all scenarios considered. The identification of risks that are common across all scenarios implicates the necessity of strategies to mitigate those risks as a key part of PNM's efforts to transition to a carbon-free portfolio, and many of the items in PNM's Action Plan are informed by the challenges ahead.

Resource Development

All scenarios modeled will require development of new resources over the next two decades at a pace that is historically unprecedented for PNM. Many scenarios include over 6,000 MW of new generation capacity on a system with approximately 3,000 MW of generation capacity today. Successfully developing new resources at such a rate will place burdens on all parties involved in the chain of resource development: PNM's internal teams responsible for planning and procurement; local, state, and federal agencies responsible for permitting; the NMPRC in its role approving PNM's resource decisions and the stakeholders involved in those processes; and the project developers and contractors responsible for timely construction of each project.

The challenge of timely resource development has recently become more acute due to recent headwinds encountered by both utilities and project developers across the industry. Since the 2020 IRP, increased demand for utility-scale renewables and storage as well as transmission and substation equipment and materials, continuing disruptions of global supply chains originating during the COVID-19 pandemic, demand for skilled labor to support engineering and construction, and interconnection queue backlogs have contributed to a significant number of project delays and cancellations. PNM experienced these challenges firsthand, having experienced multiple delays in the development of replacement resources for SJGS.

The consequences of these events are instructive: slower-than-anticipated resource development timelines required PNM to delay the final closure of SJGS and to secure short-term firm market purchases to ensure reliability, resulting in unanticipated costs to customers and higher greenhouse gas emissions. PNM is committed to working constructively with all parties involved in the resource development process to avoid similar outcomes in the future. PNM's commitment to proactive planning is reflected in multiple items in the Action Plan that represent important milestones in the development of new resources needed over the next decade.

Transmission Development

With PNM's existing transmission system nearly fully subscribed, all scenarios are also expected to require considerable additions of new transmission infrastructure to enable a transition to a carbon-free portfolio. Development of new transmission infrastructure is a challenging and often protracted process, and timelines for transmission development are typically longer than for new generation projects. The most time-consuming stage of transmission development is often the siting and permitting processes. Because of the long distance covered by transmission lines, developing a new project often requires securing agreements and approvals from multiple entities (including private landowners and local, state, and federal agencies). Additionally, generation resources are no longer being sited in a single location on a large-scale basis, which leads to significantly more dispersed investment and construction of more infrastructure as a result.

The risks associated with transmission development do not uniquely affect any of the scenarios considered – across all scenarios, failure to develop transmission in a timely manner that coincides with the need for new resources could lead to delays in PNM's continued transition to a carbon-free portfolio. However, the need for new transmission infrastructure – and by extension, the risks associated with its development – are likely to scale with the amount of new generation capacity needed.

The presence of this risk across all scenarios has multiple implications for PNM's future planning. First, ensuring new transmission development coincides with the timing of resource needs will require even more proactive planning and coordination between generation and transmission planning groups. Development timelines do not facilitate just-in-time planning and as a result, will need to be considered far earlier than traditionally needed. Second, these challenges, along with the costs associated with new transmission development, imply that existing interconnections and associated transmission rights have significant value, and PNM will seek to ensure that value is preserved for customers even as the system evolves. Both of these items are reflected in PNM's Action Plan for this IRP.

Operational and Performance Uncertainty

The IRP analysis considers a wide range of resource options, many of which are either relatively new to the market or have not yet reached commercialization. With any generation resource, there is a possibility that it may not perform as expected – but this concern is particularly acute for resources with little to no operational history. While PNM is committed to integrating new technologies into its portfolio, the company is also cognizant of the risks that accompany a rapid transition to reliance on new and emerging technologies.

Across all phases of the analysis, all portfolios studied include large amounts of new battery storage resources. By 2026, the amount of battery storage capacity in PNM's portfolio is expected to reach 1,000 MW, approaching half of system peak demand – and most scenarios include incremental storage additions in the successive five years to meet growing capacity needs. Relying heavily on a technology that has not been deployed at such scale poses multiple risks:

- **Technical risks:** as with any technology that has not been widely commercially deployed, utility-scale battery storage systems are subject to some technical risks, including potential failures of electrical equipment or degradation in performance over time. While PNM mitigates this risk by incorporating financial penalties for non-performance in energy storage agreements, these penalties will not protect customers from the consequences of unexpected failures to perform.
- **Operational risks:** PNM's resource adequacy accounting uses ELCC to measure potential contributions of storage to meet PNM's needs, which assumes batteries are dispatched optimally to meet its needs. In reality, multiple factors prevent operators from achieving perfectly optimal dispatch. Should these real-world factors prevent dispatch of storage in the ways assumed in the resource adequacy analyses, unanticipated reliability challenges could result.

This IRP uses limited real-world performance data from battery storage facilities in California to enhance planning assumptions. PNM intends to monitor closely both the performance of its own battery storage facilities and performance trends observed across the industry at large – and to use this information to update planning assumptions as soon as practicable.

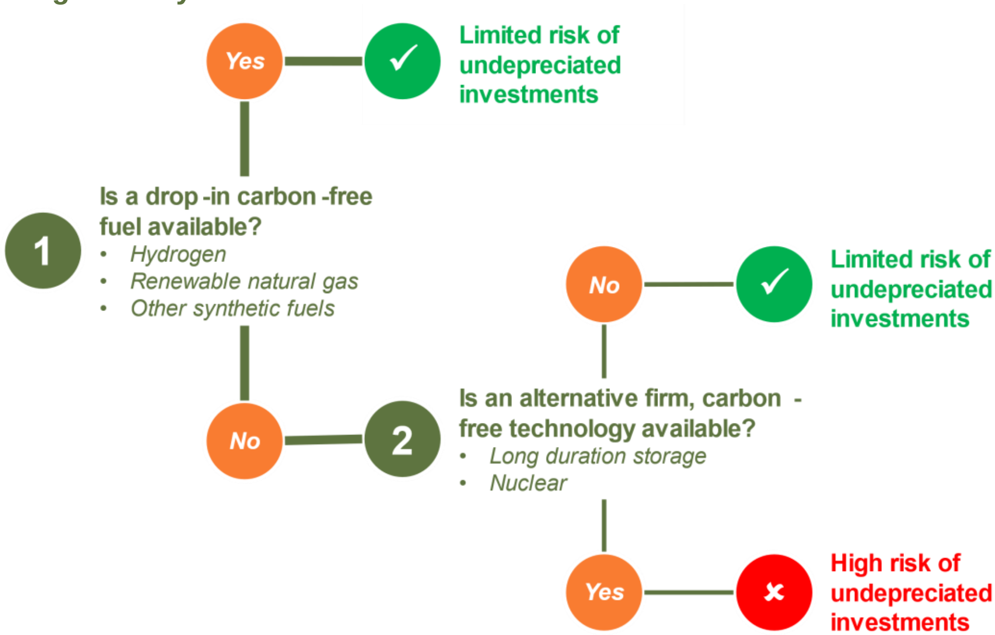
Similar risks apply to many of the emerging technologies considered in this IRP. As it has through periodic Technology RFIs, PNM intends to continue to monitor the landscape of emerging technologies closely and gather market intelligence; additionally, recognizing the value that real-world experience with new technologies can provide and the importance of leadership from first movers, the Action Plan addresses the need for PNM to participate in coordinated studies and pilot projects to demonstrate the capabilities (and learn the limitations) of new technologies.

Undepreciated Investments

One of the concerns expressed by stakeholders specific to scenarios that include investments in hydrogen-ready combustion turbines is the risk that those investments could result in undepreciated investments in fossil at the point in time that the ETA requires utilities to achieve a 100% carbon-free portfolio. In the modeling framework for considering this risk, illustrated in Figure 86, the realization of this risk depends on two questions:

- **Is a drop-in carbon emissions-free fuel available?** PNM's analysis is oriented around the idea that investments in new CTs could be repurposed to operate 100% on hydrogen by 2040, but any carbon emissions-free fuel would allow these units to continue operating as part of a carbon emissions-free portfolio even once the legal requirements of the ETA take hold in 2045. Since new CTs would have low going-forward costs, this condition alone would be sufficient to secure their position as part of a least-cost, carbon emissions-free portfolio.
- **Is an alternative firm carbon emissions-free technology available?** If a drop-in carbon emissions-free fuel is not available, the risk of stranded costs will depend on whether the CTs can be replaced in the portfolio while maintaining reliability without excessive costs. This would require an alternative firm carbon emissions-free resource, a need that could be fulfilled by long duration storage or nascent technologies like small modular nuclear reactors.

Figure 86. Framework for considering risk of undepreciated investments associated with new hydrogen-ready thermal resources



The size of this risk is also dependent upon the amount of undepreciated capital in PNM's rate base at the time these conditions materialize – which would be impacted by depreciation schedules proposed by PNM and approved by the NMPRC. Selecting depreciation schedules that align with the likely economic lifetimes of new investments can also help to mitigate against the risk of undepreciated investments.

For these reasons, while the risk of undepreciated investments is present under some circumstances, PNM does not view this risk as significant enough to warrant an outright prohibition of these types of new resources, particularly when they may provide least-cost solution to preserving reliability for PNM's customers in the near- to medium-term time horizon. PNM intends to consider the merits of these types of resources on a case-by-case basis in seeking to construct a portfolio that best meets the needs of its customers.

Wholesale Markets

Currently, utilities in most of the west plan and operate independently, sometimes reaching out to neighboring entities to buy and sell power. However, regionalization across western utilities have gained traction in two ways: forming an organized day-ahead trading market and performing regional resource adequacy planning. Since the last IRP, the CAISO and SPP formed a day-ahead marketplaces for entities in the west, EDAM and Markets+, and the Western Power Pool (WPP) initiated 20 members into the Western Regional Adequacy Program in 2022.

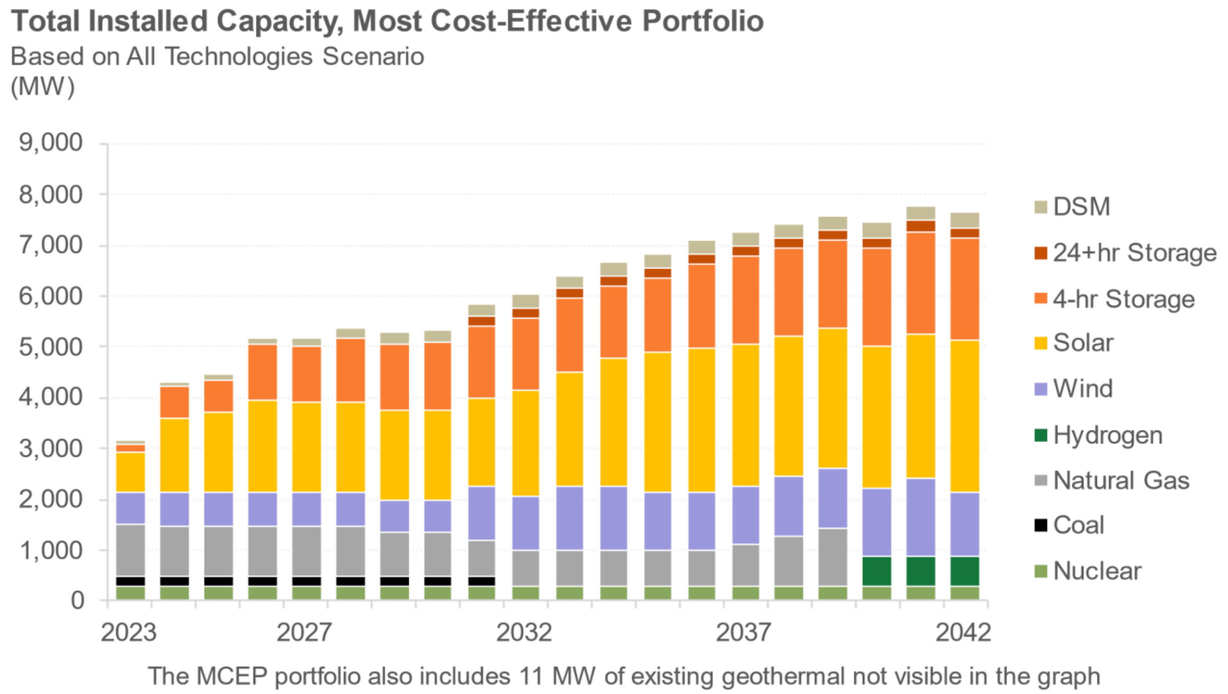
PNM actively participates in wholesale electricity markets in the Western Interconnection, and its planning process relies on certain assumptions regarding the future dynamics of wholesale markets and the availability of regional support during constrained periods. The regional grid is trending toward abundance of solar energy supply and low prices in daylight hours and scarcity during the evening hours. PNM should be prepared to be self-reliant when the region is unable to support its system. This entails procuring sufficient renewable resources and/or transmission rights to meet customer loads throughout the year, rather than depending on other jurisdictions to build enough resources to maintain a sufficient level of imports. Lagging approval or rejection of resources needed as reserves would leave PNM relying on a shrinking market availability during periods of high load. Over-reliance on the imports during peak events exposes PNM customers to increased risk of high market prices and risk of lost load.

While joining a day-ahead market and a regional planning entity has benefits, PNM continues to monitor and participate in discussions regarding regionalization to better understand the advantages and disadvantages to the system and to customers.

7.4 Most Cost-Effective Portfolio (MCEP)

PNM studied six scenarios in the final phase of analysis to inform the creation of the MCEP. Among those six portfolios, PNM has selected the **All Technologies** scenario**,** shown in Figure 87, as the MCEP for the 2023 IRP. This portfolio balances rapid deployment of known, mature technologies with targeted investment in emerging technologies to capitalize on innovation within the industry. Its optimized resource mix is expected to yield low costs and reliable service for customers, and its diversified resource mix helps to mitigate many of the risks explored both quantitatively and qualitatively in the IRP.

Figure 87. PNM’s Most Cost-Effective Portfolio



The choice of the All Technologies scenario considered a number of factors. Among the six studied, two were deemed unsuitable for further consideration as options for the MCEP for the following reasons:

- Base Technologies, which limits new supply-side investments exclusively to variable renewable and storage resources, resulted in costs that were significantly higher than any of the other portfolios studied. Incurring such high costs on behalf of customers would be irresponsible when lower cost options are available today; therefore, this case was not given further consideration.
- Base Technologies + Electrolysis, which includes new hydrogen electrolysis infrastructure in the early 2030s, was not selected as the MCEP due to the remaining unresolved questions regarding the infrastructure needs to support hydrogen deployment on a relatively short timescale and federal tax credits. While this scenario produced the lowest cost result of any considered, the low technology readiness level for hydrogen electrolysis and storage at grid scale choosing it as the MCEP. This decision notwithstanding, the low-cost result suggests that PNM should remain active in exploring the viability of this option.

Among the remaining four scenarios, variations in cost are comparatively minor – even more so when the margin of uncertainty in the technology costs included in the portfolios is considered – meaning that the selection of the MCEP from these four is also influenced by non-cost factors. PNM’s selection is motivated by the desire to be a leader within the industry, to signal to the market PNM’s willingness to collaborate and innovate on solutions that will drive the clean energy transition forward in New Mexico and more broadly, and to meet customers’ needs with a diverse, resilient supply of resources.

Selecting the All Technologies portfolio as the MCEP provides the most flexibility and diversity in low-cost carbon-free, dynamic balancing, and firm generating resources. Unlike the Base Technologies and Base Technologies + CT scenarios, this portfolio reflects an assumption that one or more long-duration energy storage technologies will become commercially available at a competitive price in the early 2030s. This calculated risk is one that PNM is incorporating into the MCEP because viable alternative portfolios that rely exclusively on mature, proven technologies that yield similar costs remain options as well. In addition, the All Technologies scenario positions PNM to adjust its strategy to incorporate hydrogen as a carbon-free fuel sooner than 2040 should barriers to deployment in the near-term prove less challenging.

Should market intelligence in the coming years provide an indication that the pace of technological innovation is unlikely to deliver these technologies to market within this time frame, PNM has flexibility to adjust its plan. For this reason, the “Base Technologies + CT” portfolio remains a viable alternative to the MCEP.

Table 69: Most-Cost Effective Portfolio (Nameplate Capacity, MW)

Resource Type	Category	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal	FGR	200	200	200	200	200	200	200	200	200	-	-	-	-	-	-	-	-	-	-	-
Contract	FGR	508	105	172	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Natural Gas	FGR	1002	1002	1002	1002	1002	853	846	846	700	700	700	700	700	700	832	996	1160	-	-	-
Hydrogen CT	FGR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	586	586	591
Nuclear	FGR	298	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288	288
Geothermal	FGR	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Solar	CFR	762	1438	1570	1783	1774	1766	1757	1749	1740	2082	2256	2511	2731	2827	2789	2781	2772	2763	2833	3000
Wind	CFR	658	658	658	658	658	658	658	658	1058	1058	1258	1258	1156	1156	1156	1156	1156	1356	1556	1250
Storage (4hr)	DBR	170	620	632	1110	1110	1275	1319	1344	1403	1444	1444	1444	1461	1660	1714	1714	1714	1960	2010	2012
Storage (8-12hr)	DBR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage (24+hr)	DBR/FGR	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200	200
DSM	CFR/DBR	69	96	117	135	154	197	215	235	258	280	260	262	280	274	279	272	284	300	311	310
Total		**3,478**	**4,217**	**4,450**	**4,987**	**4,997**	**5,047**	**5,095**	**5,131**	**5,658**	**6,063**	**6,418**	**6,675**	**6,827**	**7,116**	**7,269**	**7,418**	**7,586**	**7,465**	**7,797**	**7,662**

* CFR = Carbon-free energy resources, DBR = Dynamic balancing resources, FGR = Firm generating resources

8 Conclusion

8.1 Statement of Need

The PNM Integrated Resource Plan 2023 outlines an innovative long-range path for building out a reliable generation portfolio for customers over the next 20 years based on current planning assumptions and technologies. The IRP identifies a need for between 5,800 and 8,000 MW of new generation capacity through 2042. This total amount of future capacity is almost twice as much as exists in PNM's portfolio today and must be constructed and integrated at an unprecedented pace to achieve PNM's goal of a carbon-free electric system. Simultaneously, changes are occurring and must occur in every sector of the environment in which PNM operates. These portfolio changes will also impact and be influenced by transmission and distribution grid planning activities. As a result of all these dynamic factors, we expect an ongoing re-evaluation and modifications to the 2023 IRP that will be incorporated in future triennial PNM IRPs or identified through the filing of material changes to this IRP, as appropriate.

The IRP planning framework balances three overarching objectives: maintaining reliability, minimizing cost, and mitigating impact to the environment. The IRP seeks to create a long-term plan that achieves favorable results for PNM customers in all three areas:

- **Reliability:** PNM customers expect steady, reliable electric service. To meet this expectation, PNM plans the system to maintain a loss of load expectation of "one day in ten years," aligned with common industry standards; doing so requires planning a generation portfolio to meet customer demands all hours of the year, including under increasingly severe extreme weather conditions. As significant portions of the existing fossil generation portfolio will retire over the planning horizon, PNM needs to add new resources that, together, can reliably supply customers across all potential weather or extreme event conditions.
- **Affordability:** PNM considers comprehensive, lifecycle costs when determining the affordability of resources in its portfolio. Avoiding unnecessary expenses and minimizing costs to consumers is a central concept of affordability; however, it is also important to maintain a more nuanced perspective to manage costs over the long term. Therefore, affordability also includes a consideration of mitigating potential risks and volatility in the future.
- **Environmental Impact:** PNM has established an ambitious goal to achieve a 100% carbon-free generation portfolio by 2040, five years in advance of the ETA requirement. As of 2022, PNM's generation portfolio met 53% of customers' total annual energy needs (10,000 GWh) with carbon-free electricity. The IRP must therefore include sufficient new carbon-free resources to displace the remaining fossil generation in the current portfolio and meet future load growth – a total incremental need of 10,000 GWh of carbon-free energy by 2042.

Achieving PNM's goals will require a sustained, concerted effort to transform its portfolio, a transformation that also requires constant evaluation, coordination with stakeholders, and adjusted as needed to respond to evolving conditions.

The types of resources procured to serve PNM customers will include a diverse mix of technologies and capabilities that generally fall into three categories:

- **Low-cost carbon-free energy resources** with the capability to produce clean energy to meet a majority of customers' energy needs throughout the year. Examples available today include solar PV, wind, and energy efficiency.
- **Dynamic balancing resources** that provide operators with the tools to balance the supply and demand for electricity on an instantaneous basis, recognizing that the generation profiles of many of the carbon-free resources will not coincide naturally with electricity demand. Examples include shorter-duration energy storage and demand response.

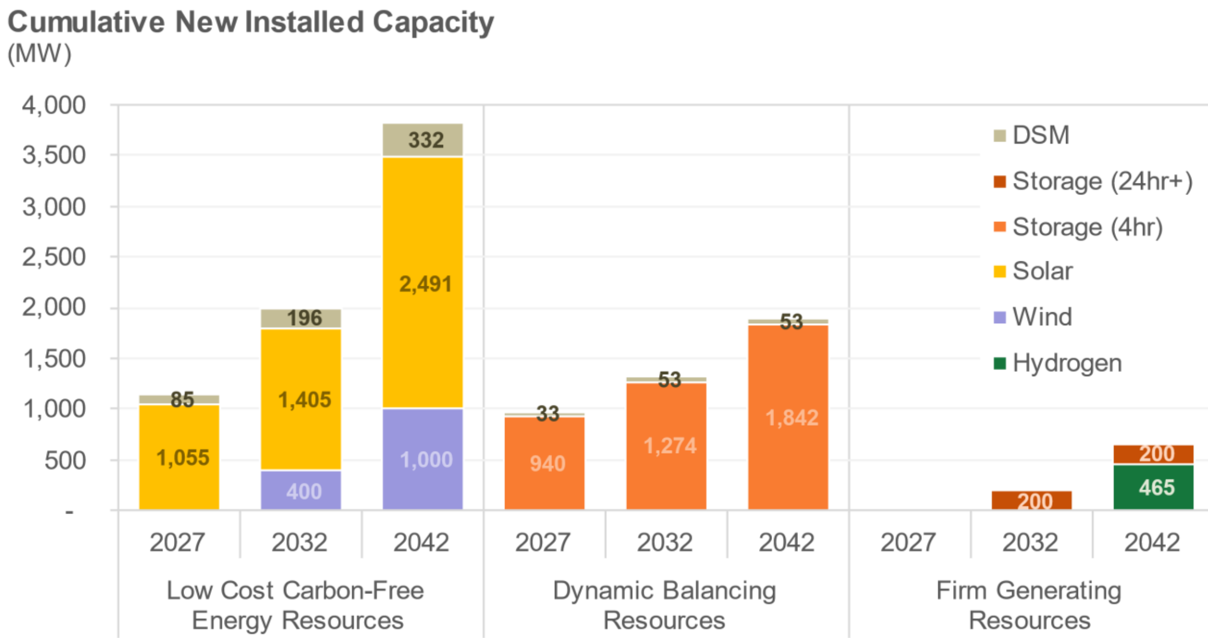
- **Firm generating resources** with the capability to operate at or near full capacity for extended periods of time that will allow PNM to maintain reliability even under the most constrained conditions in the system, which may include both periods of high demand as well as periods of low output from variable resources. Today, these needs are met with nuclear and fossil fuel resources; in the future various emerging technologies including hydrogen and long-duration storage are planned to be used to satisfy these needs.

Based on what PNM knows today and its expectations for the future, the Most Cost-Effective Portfolio reflects the current vision of the resources that would best fulfill future resource needs. Figure 88 summarizes the new resource needs in the MCEP at three key milestones: 2027, at the end of the Action Plan; 2032, after exit from Four Corners and the end of the depreciable life of Reeves; and 2042, at the end of the planning horizon.

- Between now and 2027, PNM plans to meet most of its needs with 1,100 MW of low-cost carbon-free resources and 1,000 MW dynamic balancing resources, most of which are already under development (in some cases, pending approval by the NMPRC) or will be procured through active solicitations.
- Between 2027 and 2032, resource needs grow due to load growth and plant retirements, and during this period, PNM's MCEP identifies an additional 900 MW of low-cost, carbon-free energy resources, 400 MW of dynamic balancing resources, and 200 MW of firm generation resources.
- Between 2032 and 2042, the MCEP identifies an additional 1,800 MW of low-cost carbon-free resources, 600 MW of dynamic balancing resources, and 500 MW of new firm generating resources in this last decade in the planning horizon.

Additional details on the MCEP can be found in the Appendices.

Figure 88. Summary of future resource needs in the Most Cost-Effective Portfolio



Cumulative figures reflect all new resource additions beginning in 2024, inclusive of projects under development:

Solar PV: *Atrisco (300 MW), Quail Ranch (100 MW), San Juan (200 MW), Sky Ranch (190 MW), TAG I (140 MW), Community Solar (125 MW)*

Storage: *Atrisco (300 MW), Quail Ranch (100 MW), Route 66 (50 MW), San Juan (100 MW), Sandia (60 MW), Sky Ranch I (50 MW), Sky Ranch II (100 MW), TAG I (50 MW), distribution-level storage (12 MW)*

DSM: *2024 & 2025 approved DSM programs*

While the MCEP reflects the current view of the most viable pathway to PNM's 2040 carbon-free goal, there are multiple uncertainties that may change the composition of the portfolio. By studying a diverse range of scenarios in this IRP, PNM's planners and stakeholders will have the requisite information to understand and assess the options and influencing factors that may lead to a change of course from the current MCEP. In this regard, the IRP explores all viable pathways to decarbonization by 2040, while recognizing that the numerous future alternatives and sensitivities studied broaden the range of plausible resource needs going forward:

Table 70. Ranges of new capacity additions across the planning period

	Ranges of Cumulative New Installed Capacity (MW)		
	Through Action Plan Window (2027)	**Through Medium Term (2032)**	**Through Planning Horizon (2042)**
Low-cost carbon-free energy resources	1,100 – 1,200	1,500 – 2,200	3,300 – 4,500
Dynamic balancing resources	900 – 1,000	1,000 – 1,700	1,600 – 3,300
Firm generating resources	0	0 – 500	500 – 900
All resources	**2,000 – 2,100**	**3,100 – 3,700**	**5,800 – 8,000**

Ranges shown informed by results across four scenarios (All Technologies, Base Technologies + CT, Base Technologies + LDES, and Base Technologies + CT + LDES) across all sensitivities excluding Stable ED (high load growth). Resource needs under a high load growth future could be considerably higher.

The specific resources that are procured to meet those needs will include a diverse mix of technologies. Many of these resources are commercially available today, but the pursuit of aspirational goals often requires a transformative approach. Therefore, PNM will continue to explore innovative solutions including long-duration storage and hydrogen fuels as they approach commercial viability. PNM recognizes the importance of early action in the lifecycle of technology maturation, and to the extent practical opportunities arise, PNM will partner with others in the industry to engage in pilot programs and small-scale demonstrations of emerging technologies.

The development of new generation resources at the scale needed to meet the challenges ahead has implications for other parts of the system. In particular, the new resources added to decarbonize the generation mix and meet growing loads will require an expansion of the transmission system to allow for the delivery of electricity. The existing transmission system is already encountering constraints today, and many of the resources that may help to satisfy future needs are located in parts of the state that would require new transmission investments.

Ultimately, the specific portfolio of resources that best meets the needs of PNM's customers and achieves its goals will be determined by a combination of market forces, technological advances, and industry trends that cannot be perfectly predicted today; further, specific decisions around procurement of new resources will occur through competitive solicitations to ensure customers benefit from the lowest cost options. PNM's planning and procurement processes are adaptive and iterative by design, and neither the presence nor the absence of any specific type of resource in the 2023 IRP MCEP is a prescriptive determination of what will or will not be procured to meet customer needs. This MCEP, coupled with the diverse outcomes in alternative plausible portfolios, informs an Action Plan that is intended to further progress towards decarbonization while preserving optionality to adjust to changing market circumstances.

8.2 Action Plan

As the final result of the 2023 IRP, the Action Plan translates learnings from the IRP process into concrete, actionable steps that will support progress towards long-term system reliability and decarbonization. It reflects the fact that procurement processes to meet the 2026-2028 resource needs are already underway and focuses on actions that will lay the foundation for the continued transition towards a carbon-free system. Many of the elements of the Action Plan have been heavily influenced by the feedback received from stakeholders throughout the facilitated process; where possible, the Action Plan highlights how stakeholder input helped to shape these actions.

1. Issue an all-source RFP for resources coming online between 2029 and 2032

- Utilize an independent evaluator as part of the RFP process;
- Consider environmental justice factors in the bid evaluation process;
- Include system reliability and resiliency assessments, specific preferred transmission location(s) and constraints, fuel security, and resource diversity in the bid evaluation process;
- Leverage federal sources of funding, including the IRA, to the extent practical in alignment with system resource timing needs; and
- File well in advance for resource approvals with the NMPRC (PPA/CCN), balancing resource selections between utility-owned and third-party contracts to ensure project timelines properly support reliability.

Stakeholder input: *During the facilitated stakeholder meetings, many stakeholders expressed interest in and enthusiasm for pursuing specific types of resources (e.g., geothermal, closed-loop pumped storage, etc.) or siting of new resources with specific criteria (e.g., environmental justice). In response, PNM reiterated its commitment to utilize all-source RFPs to maximize value for customers. Within the context of competitive procurement processes, PNM invited stakeholders to provide specific suggestions for RFP instructions and evaluation methodology in the IRP docket, as RFP instructions to bidders and form contracts will be filed with the NMPRC prior to issuance.[52] Certain accommodations were made to Action Plan Item 1, including updates to RFP documents and assurances of fair consideration of all responding resources.*

2. Issue an RFI/RFP for long-lead time resources or newer technologies that could deliver between 2029 and 2035 process

- Consider environmental justice factors in the bid evaluation
- Continue to assess longer term needs of the system, including potential transmission expansions, to help facilitate long lead or newer technology additions;
- Continue to monitor the state of maturation of emerging technologies that are not yet commercially viable or cost-effective;
- Participate in coordinated studies and pilot programs for emerging technologies as practical and appropriate; and,
- Encourage solicitation of federal sources of funding, including the IRA, to the extent practical in alignment with system resource timing needs.

[52] NMAC 17.7.3.12(C)

Stakeholder input: *Stakeholders also expressed interest in the exploration of emerging technologies through federal or state research programs, pilot projects, and/or other industry partnerships. PNM's commitment to pursue these types of opportunities when practical is reflected in Action Plan Item 2.*

3. Evaluate opportunities to abandon FCPP earlier than 2031 as available and in the interest of customers

- Address the energy and capacity implications of removing this resource from the portfolio earlier than scheduled;
- To the extent that abandonment of FCPP and replacement resources are available and provide benefit to PNM customers, file for abandonment of FCPP interest; and,
- Seek IRA funding, including the "energy community" bonus, to maximize benefits, mitigate financial costs, and promote an equitable transition.

Stakeholder input: *During the facilitated stakeholder meetings, some stakeholders asked PNM to prioritize projects and resources located within federally designated "energy communities" (supported by the IRA) to deliver low-cost clean energy to while providing economic development opportunities in communities that are transitioning away from a fossil fuel-based economy. In response, PNM has incorporated this concept as part of Action Plan Item 3. PNM also notes that such projects' ability to take advantage of the energy community bonus tax credits in the IRA may allow them to compete more favorably in competitive solicitation processes.*

4. Evaluate the ability to create new (or improve existing) demand response and other customer programs (e.g. customer sited storage, interruptible rates)

- Continue to develop and implement cost effective energy efficiency and demand management programs and file plans with the Commission, as applicable;
- Continue to explore, develop, promote and refine, dynamic pricing structures (e.g., TOU) offered by PNM to empower customers and promote an efficient use of the system;
- Engage with stakeholders and seek feedback regarding potential new customer programs that could be enabled through Gridmod/AMI and consider how these could be incorporated in future IRPs; and
- Consider new DR programs, including flexible requirements, with the goal of improving performance during peak risk periods.

Stakeholder input: *During the facilitated stakeholder meetings, stakeholders requested that PNM further develop its demand response programs and define a specific goal for demand response. Establishing a specific target would be inconsistent with pursuit of most cost-effective resource portfolio to meet customers' needs through the competitive resource procurement process; however, PNM recognizes the importance of continuing to explore further opportunities to refine its customer programs. This is reflected in Action Plan Item 4.*

5. Assess the ability to add capacity at PNM's existing plant sites

- Conduct site assessments for resources approaching the end of contract or end of depreciable life to study (1) transmission impacts for potential alternatives pursuant to the FERC Open Access Transmission Tariff rules and (2) the necessity of extending operations of existing resources to enable reliable operations of the system;
- Continue to explore options to expand the capability of existing plant resources when evaluating alternatives to meeting future customer needs, also pursuant to the FERC Open Access Transmission Tariff rules; and
- Examine potential non-wires solutions where feasible to increase existing plant capacity or operational flexibility.

6. Continue to explore the expanded participation in regional markets

- Explore PNM's ability to make a binding commitment to Western Resource Adequacy Program (WRAP) sooner than 2028;
- Actively explore joint regional market opportunities, formal or informal, to assess the potential customer benefits associated with market participation. Provide input, when possible, to explore benefits associated with extreme event(s) both from a cost and performance perspective.

Stakeholder input: *During the facilitated stakeholder meetings, stakeholders recommended that PNM explore the benefits of participation in organized regional markets, noting specifically the importance of potential cost savings and reliability improvement during extreme weather conditions. Consistent with these recommendations, PNM intends to continue exploring opportunities to participate in organized markets and has included actions associated with market participation as part of Action Plan Item 6.*

7. Assess the need to utilize other reliability metrics in planning

- Transition resource adequacy modeling approach to reflect WRAP planning requirements and resource attributes no later than PNM's 2026 IRP;
- To the extent these resource attributes and planning requirements are known, and PNM makes a binding commitment to fully participate in WRAP earlier then 2028, update resource adequacy modeling for PPA and/or CCN filings, targeting prior to filing the 2026 IRP if possible;
- Continue to monitor whether the loss of load expectation (LOLE) standard of 0.1 days per year is sufficient for planning;
- Assess whether additional metrics should be utilized in resource adequacy planning and/or whether standards for resilience should be established for planning; and
- Explore additional methods to evaluate incorporation of distribution planning concepts into Integrated System Planning.

Stakeholder input: *Throughout the facilitated stakeholder meetings, stakeholders provided multiple valuable comments related to resource adequacy and reliability. Some stakeholders noted that PNM's future plans to participate in WRAP should be reflected in its resource adequacy modeling; some called upon PNM to explore in greater detail the implications of extreme weather; and some voiced concerns over high penetration of distributed resources on distribution feeders* *potentially causing reliability and resource accessibility issues. All of these comments point to a general desire for continued refinement and understanding of PNM's approach to planning for reliability, and those recommendations are addressed in Action Plan Item 7.*

8. Initiate stakeholder workshops and meetings for the 2026 IRP in advance of the required six-month stakeholder process outlined in the updated IRP Rule

- Investigate improvements to IRP process to incorporate integrated transmission, and distribution into more integrated system planning;
- Request input from stakeholders at the outset of the 2026 IRP stakeholder process regarding areas of focus and prioritization of activities for the 2026 IRP, including consideration of recommendations emanating from the 2023 IRP process; and
- Investigate ways to provide meaningful education and outreach for stakeholders and enhance engagement for the 2026 IRP cycle.

Stakeholder Input: *Many of the stakeholder comments and recommendations throughout the process were outside the defined scope of this IRP cycle or were explored in a limited fashion; PNM values this input and will incorporate improvements and refinements to future planning efforts. Examples included recommendations for consideration of additional scenarios and additional modeling detail on topics like correlated gas outages, extreme weather, and battery performance. Some stakeholders expressed a more general desire to see PNM initiate public information efforts regarding electricity sector changes and the IRP process. In response, this activity was included as part of Action Plan Item 8.*

9. Complete the 2026 IRP

- Address the implications of the expiration of supply contracts and any retiring resources;
- Investigate potential optimization of generation, storage, and transmission to enhance planning efforts; and,
- Work with stakeholders in an ongoing collaborative public advisory process, including communication of electricity sector changes and the IRP process.